SCOTTISH POWER PLC
Form 6-K
June 23, 2005
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SECURITIES AND EXCHANGE COMMISSIONS

WASHINGTON, DC 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER

PURSUANT TO RULE 13a-16 OR 15a-16 OF

THE SECURITIES EXCHANGE ACT OF 1934

For the month of June 2005

SCOTTISH POWER PLC

(Translation of Registrant s Name Into English)

CORPORATE OFFICE, 1 ATLANTIC QUAY, GLASGOW, G2 8SP

(Address of Principal Executive Offices)

(Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F.) Form 20-F x Form 40-F ¨

(Indicate by check mark whether the registrant by furnishing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.) Yes ¨ No x

(If Yes is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-_____ .)

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

/s/ Scottish Power plc

(Registrant)

Date June 23, 2005

By: /s/ Donald McPherson

Donald McPherson

Assistant Secretary

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Financial Highlights

	2005	2004	**2005***	2004*
Turnover	**£6,849m**	£5,797m	**$12,945m**	$10,666m
Operating profit	**£153m**	£1,023m	**$289m**	$1,882m
Operating profit excluding goodwill and exceptional	**£1,197m**	£1,151m	**$2,262m**	$2,118m
(Loss)/profit before tax	**£(29)m**	£792m	**$(55)m**	$1,457m
Profit before tax excluding goodwill and exceptional	**£1,015m**	£920m	**$1,918m**	$1,693m
(Loss)/earnings per ordinary share/per ADS	**(16.83)p**	29.40p	**$(1.27)**	$2.17
Earnings per ordinary share/per ADS excluding goodwill and exceptional	**40.22p**	36.40p	**$3.04**	$2.69
Dividends per ordinary share/per ADS	**22.50p**	20.50p	**$1.65**	$1.42

* Amounts for the financial years ended 31 March 2005 and 31 March 2004 have been translated, solely for the convenience of the reader, at the closing exchange rates on 31 March of $1.89 to £1.00 and $1.84 to £1.00, respectively. Dividends per American Depositary Share (ADS) are shown based on the actual amounts in US dollars. One ADS represents four ordinary shares.

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ScottishPower is an international energy company listed on both the London and New York Stock Exchanges.

Through its operating subsidiaries the company provides in excess of 6.7 million electricity or gas services to homes and businesses across the UK and in the western US.

This Annual Report & Accounts examines our performance in 2004/05 and assesses the issues and opportunities ahead.

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In the year ahead we remain committed to our strategy of investing for organic growth and improving operational performance in our three continuing businesses.

Charles Miller Smith Chairman

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Chairman s Statement

Introduction and Background

On 24 May 2005 we announced the decision to sell our regulated US business PacifiCorp to MidAmerican Energy Holdings Company (MidAmerican) for $9.4 billion following a strategic review.

The review examined PacifiCorp s requirement for future capital investment, the scope to achieve further efficiency improvements and the potential to increase its rates of return. We assessed these factors against likely developments in the regulatory environment.

Following the completion of the review, the Board concluded that in view of the scale and timing of PacifiCorp s capital investment requirements, relative to the profile of anticipated returns, shareholders   interests would be best served by a sale of PacifiCorp and, following completion of the sale, the return of approximately $4.5 billion of the $5.0 billion net proceeds of the sale to shareholders.

The sale of PacifiCorp requires the approval of shareholders and a number of regulatory approvals in the US, which we anticipate will take 12-18 months to complete. During that time we expect that there will be no material changes to the running of the business. We shall seek shareholder approval at an Extraordinary General Meeting.

Business Progress

Looking ahead, we will focus our management and capital on our UK and Infrastructure Divisions and on our competitive US business, PPM

pence, bringing the total dividends for the year to 22.50 pence, an increase of 10% on last year.

In the year ahead we remain committed to our strategy of investing for organic growth and improving operational performance in our three continuing businesses.

Staff

ScottishPower s performance is due to the skills, knowledge and innovation of my colleagues throughout the company. Their professionalism and determination deserve my thanks and those of my Board. I would also like to emphasise ScottishPower s continuing commitment to upholding the highest standards of health, safety, environmental stewardship and corporate responsibility.

Board Changes

After the 2005 AGM Philip Carroll, who joined the ScottishPower Board in January 2002, will retire from his position as Non-Executive Director. On behalf of the Board, I thank him for his diligent and committed service and wish him well.

Summary

Energy, each of which has strong growth prospects.

These businesses have been very successful achieving, in aggregate, an improvement in operating profit of 38% during the last two years. We intend to build on this excellent platform with targeted investment of some £4.5 billion by 2010 to create long-term value and further improvements in operational performance.

During the year ScottishPower performed satisfactorily, achieving profit before tax* of more than £1 billion for the first time, an increase of 10% on the previous year. The group s earnings per share* of 40.22 pence were up by 10% on the previous 12 months, and the final quarter dividend was 7.65

** Excluding goodwill amortisation and the exceptional item*

We believe the decision to sell PacifiCorp to MidAmerican is the right one for our shareholders and the right one for ScottishPower.

Focusing our management and capital on our continuing businesses will enable us to pursue additional investment opportunities to achieve growth and create value for our shareholders. Our current dividend policy is to grow dividends broadly in line with earnings and we expect this to continue following the sale and return of capital to shareholders.

Charles Miller Smith Chairman

24 May 2005

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Following the sale of PacifiCorp, we will focus our management and capital on our Infrastructure Division, UK Division and PPM Energy. These three businesses have strong positions, combined with a market and regulatory environment which we anticipate will continue to provide attractive opportunities for increasing returns and organic growth. This year we achieved profit before tax* of over £1 billion for the first time, an increase of 10% compared with the prior year.

Ian Russell Chief Executive

** Excluding goodwill amortisation and the exceptional item*

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Chief Executive s Review

1 Sale of PacifiCorp

Introduction

In November 2004, the Board began a strategic review of PacifiCorp as a result of its performance and the significant investment it required in the immediate future.

Our review examined PacifiCorp s future capital investment requirements, the likely development of its regulatory regimes, the scope for further operational efficiencies and improvements and the scale and timing of further improvements in its achieved rates of return. We also considered the opportunities for growth and returns that exist in our three other businesses.

The Board concluded that, in the light of the scale and timing of the capital investment required in PacifiCorp and the likely profile of returns from that investment, shareholders interests were best served by a sale of PacifiCorp and return of capital to shareholders.

The Board, therefore, has entered into a binding agreement for the sale of PacifiCorp to MidAmerican for $9.4 billion. The Board intends to return approximately $4.5 billion of the net proceeds of $5.0 billion from the sale of PacifiCorp, to shareholders. This capital return is anticipated to occur following completion of the sale. The details of the capital return will be communicated to shareholders in due course.

The sale of PacifiCorp enables us to focus our management and capital on the continued development of the Infrastructure Division, UK Division and PPM Energy. These businesses have driven our profit growth over approximately $4.5 billion of the net proceeds from the sale to shareholders following the completion of the sale. The sale and return of capital is expected to be earnings accretive for ScottishPower from completion.

An exceptional impairment charge of £927 million, under UK GAAP, has been made in ScottishPower s results for the year ended 31 March 2005. This impairment provision has been made to reduce the book value of PacifiCorp down to its expected net realisable value. Pending completion of the sale, PacifiCorp will be treated as a discontinued operation in the financial statements of ScottishPower. The impairment amount excludes foreign exchange gains of £485 million, achieved to date, which will be reflected in ScottishPower s Income Statement under IFRS on completion of the sale of PacifiCorp to MidAmerican.

Going forward, our current dividend policy is to grow dividends broadly in line with earnings and we expect this to continue following the sale and return of capital to shareholders. Our financial strategy will be to retain an A category credit rating for the group and our principal operating subsidiaries. To achieve this rating, on completion of the sale, the group will target credit ratios of adjusted FFO/net debt of greater than 25% and FFO/interest cover of more than five times. ScottishPower will work closely with the rating agencies in order to ensure its rating objectives are achieved.

For the year ended 31 March 2005, PacifiCorp s UK GAAP profit before tax, excluding goodwill amortisation and the exceptional item, was $581 million and net assets were $ 4.1 billion as at 31 March 2005. From the perspective of PacifiCorp, its unaudited earnings under US GAAP were $250 million for the same period.

Strategy for ScottishPower

the last two years and delivered overall returns ahead of our cost of capital. They have substantial opportunities for continued growth through capital investment and improved operational performance.

Financial Impact of the Sale and Return of Capital

MidAmerican will be acquiring the equity of PacifiCorp for $5,109.5 million and will be assuming net debt at completion expected to be approximately $4.3 billion, which gives a total sale price for PacifiCorp of $9.4 billion. Allowing for that net debt, with no material tax cost expected and after estimated costs, net proceeds from the sale are expected to be approximately $5.0 billion. ScottishPower intends to return

Following the sale, ScottishPower will continue to develop its Infrastructure Division, UK Division and PPM Energy, where ScottishPower has strong positions, combined with a market and regulatory environment that it is anticipated will continue to provide attractive opportunities for organic growth and investment. These businesses have also driven ScottishPower s recent profit growth and offer the most attractive returns. In aggregate, these three divisions have shown growth in operating profit of 38% over the last two years.

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Chief Executive s Review

The Infrastructure Division can benefit from increases in allowed revenue as a result of the recently concluded Distribution Price Control Review and Transmission Price Control Extension. The resulting price controls provide increased revenue allowances for taxation and pension costs, reflect higher capital investment levels and introduce new incentive targets. The division has geared up across its activities to achieve and, where possible, outperform those new targets and to deliver the increased investment programme. We expect capital expenditure in the division to amount to approximately £1.7 billion to 2010, with 40% of that figure associated with growth in the business.

In our UK Division, over the medium-term, we aim to continue to grow profitably our customer base and generation assets. The growth in customer numbers is expected to deliver increased earnings via higher revenues and a reduction in our average cost to serve. We will support this growth in customer numbers with further investment in generation and gas storage and aim to invest approximately £1.4 billion of capital to 2010. This includes the continued expansion of our windfarm portfolio, where we aim to invest £1 billion by 2010. Some 75% of UK Division s capital expenditure is expected to support growth, with targeted returns immediately following completion of each project for new investments of at least 300 basis points above the division s weighted average cost of capital.

At PPM Energy we expect to see continued strong growth in the medium-term coming from our investments in windfarms and gas storage. Approximately £1.4 billion of capital is expected to be invested to 2010, almost all for growth, including £950 million for new wind capacity, taking our total to at least some 2,300 MW and £460 million in the same period to increase our gas storage capacity to 125 BCF. Returns of at least 300 basis points above PPM Energy s weighted average cost of capital are expected immediately following completion of each project.

Details of the PacifiCorp Sale

The sale is subject to Securities and Exchange Commission, Department of Justice or Federal Energy Regulatory Commission, Federal Trade Commission and Nuclear Regulatory Commission approvals at federal level, without conditions that would have a material adverse effect on the PacifiCorp business. In addition it is subject to approval at state level in Utah, Oregon, Wyoming, Washington, Idaho and California provided such state approvals are not subject to conditions whose effect would be meaningfully adverse to the business of PacifiCorp. The directors of ScottishPower anticipate that such approvals should be forthcoming within 12 to 18 months. The sale is subject to further conditions to completion which include the representations and warranties of the parties remaining true and correct, the parties performing their covenants and obligations under the Agreement in all material respects, and no material adverse effect in relation to PacifiCorp having occurred. The Agreement may be terminated prior to completion by mutual agreement of the parties or otherwise in certain circumstances including material breach of the representations, warranties or covenants of the parties, ScottishPower shareholders not approving the sale or the sale not having been completed by 23 May 2006 or in certain circumstances by 17 February 2007 and (by MidAmerican) where the Board of ScottishPower withdraws or adversely modifies its recommendation of the sale. ScottishPower has also agreed that it will not initiate, solicit or engage in negotiations concerning any alternative proposals relating to PacifiCorp other than in certain specified circumstances.

ScottishPower and MidAmerican have agreed certain break fee arrangements. In summary, ScottishPower has agreed to pay MidAmerican a break fee of $10 million if, prior to ScottishPower shareholders approving the sale, an alternative proposal relating to PacifiCorp or a proposal for the acquisition of control of ScottishPower is made or announced, is rejected by ScottishPower, and ScottishPower shareholders do not subsequently approve the sale at the relevant shareholders meeting or in any event before 1 September 2005 and the Agreement with MidAmerican is as a result terminated. If the break fee would otherwise become payable then its amount is increased to (a) $100 million (in total) if the ScottishPower Board instead of rejecting such proposal, recommends it or withdraws or adversely modifies its recommendation of the sale and (b) $250 million (in total) if within a year of the Agreement with MidAmerican terminating, ScottishPower enters into an agreement with respect to or consummates an alternative proposal relating to PacifiCorp or a proposal for the acquisition of control of ScottishPower. The maximum break fee payable by ScottishPower is therefore $250 million. A break fee of $250 million is payable by MidAmerican to ScottishPower if ScottishPower terminates the Agreement as a result of MidAmerican agreeing to or announcing a proposal to acquire certain competing utility and energy assets if the same directly or indirectly results in the failure to satisfy certain regulatory conditions to the sale and/or creates or imposes additional conditionality or costs which result in MidAmerican choosing not to complete or to terminate the Agreement.

Prior to sale it is envisaged that PacifiCorp will be managed and developed as currently, with no material changes to its operating plans, management structures, or boards.

Between now and closing of the sale, ScottishPower has agreed to invest additional equity in PacifiCorp to fund ongoing capital expenditure in line with PacifiCorp s current plan. Pursuant to these arrangements, ScottishPower will invest $500 million during the financial year 2005/06. In addition ScottishPower has agreed to make further investments during the financial year 2006/07 of up to $525 million, contributed quarterly, although ScottishPower will be fully compensated for any such payments made in respect of the financial year

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2006/07. Between now and the closing of the sale, ScottishPower is entitled to dividends from PacifiCorp in line with PacifiCorp s current plan. Pursuant to these arrangements, it is expected that, ScottishPower will receive $215 million of dividends during the financial year 2005/06, and $242 million of dividends during the financial year 2006/07, these amounts to accrue monthly.

Due to the size of the sale, the approval of ScottishPower s shareholders is required. Accordingly, a circular containing details of the sale and a notice convening a general meeting will be posted to shareholders in due course. It is expected that the details of the return of capital will be sent to shareholders around the time of completion of the sale. The sale, which is conditional on shareholders approval and on regulatory clearance, is expected to complete in 12 to 18 months.

2 Financial Results

We have achieved profit before tax* of over £1 billion for the first time, an increase of 10% compared with the prior year. These results reflect a 20% growth in our UK customer numbers complemented by investments in generation, continued efficiency in our UK network business, further returns from our US competitive wind and gas storage investments, and lower interest costs. These contributions more than made up for the lower profit at PacifiCorp.

We continue to see very attractive opportunities for profitable growth in our UK network business, where the finalisation of the Distribution Price Control Review places us in a good position to continue to outperform the targets and enhance returns. We are the leading developer of wind generation in the UK and the US with approximately 1,000 MW of plant in operation and some 700 MW of plant to be constructed in the remainder of 2005.

PacifiCorp s financial performance was impacted by milder temperatures and lower thermal generation availability in the first half, and a lack of rainfall and snow held back the contribution from our hydroelectric generation plants in the second half. The lower than normal snow and rainfall over the winter months will also reduce hydroelectric generation availability during the first six months of 2005/06.

The Infrastructure Division delivered an increase in operating profit of 6% in the year and concluded the Distribution Price Control Review and Transmission Price Control Extension. The division will benefit from increases in allowed revenue as a result. The price controls also introduce challenging new incentive targets which will require further improvements in operational performance. The division is focused on outperforming these new targets and delivering the increased investment programme.

In the UK Division the investment in generation plant has complemented significant growth in customer numbers, up 865,000 this year to over 5.1 million. Together, these have contributed to the substantial increase of some 80% in the operating profit* of the division. We are continuing to grow our customer numbers, albeit at a slower rate than experienced in the first nine months of 2004/05, while maintaining our focus on gaining profitable customers that will create shareholder value. Generation has started at the Black Law windfarm and construction is underway at the Beinn Tharsuinn and Coldham windfarms. The UK Division has continued to demonstrate significant progress toward its renewable energy strategy.

PPM Energy continued to grow rapidly with operating profit* rising 60% to £59 million, for the year, with additional earnings delivered through Production Tax Credits on wind output. In the year we acquired Atlantic Renewable Energy Corporation in order to expand on the east coast of the US. This acquisition and the recently announced Shiloh and Maple Ridge windfarms, together with windfarms at Klondike II, Trimont and Elk River, gives PPM Energy 574 MW due on-line by 31 December 2005, all of which are expected to be immediately earnings enhancing following completion.

3 Investing for Growth

We continue to execute our investment strategy across the group and invested £1.4 billion during the year, with £0.8 billion (60%) invested for growth. Investments in our regulated businesses aim to achieve at least the allowed rate of regulatory returns, while our competitive businesses are expected to achieve returns of at least 300 basis points above each division s weighted average cost of capital.

PacifiCorp s net capital investment was £480 million for the year, with £231 million (48%) invested for organic growth. Of this, £136 million was invested in building new generation. The first phase of the 525 MW Currant Creek plant, representing 280 MW, will be operational this summer with full operations scheduled to begin in summer 2006. Construction at the 534 MW Lake Side plant is scheduled to begin this summer. A further £95 million was invested in new connections and network reinforcement.

Infrastructure Division s net capital investment was £267 million for the year, with £67 million (25%) invested for organic growth, including expenditure on the connection to the Black Law windfarm and other new customer connections. Other organic investment focused on network reinforcement projects, such as the £30 million, five-year, Liverpool city centre regeneration programme and initial spend on the Renewable Energy Transmission Study upgrade programme required to accommodate the connection of renewable generation in Scotland. As a result of the Distribution Price

** Excluding goodwill amortisation and the exceptional item*

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Chief Executive s Review

Control Review, capital expenditure allowances increase by 55% over the next five years, against the previous control period, with some 1,800 km of overhead lines due to be built. New initiatives in operational excellence will also help our drive towards a 30% improvement in network performance, resulting in reduced fault duration for our customers and minimising risk of financial penalty from Ofgem. We also plan to invest some £190 million in the first phase of the Transmission Investment for Renewable Generation.

The UK Division s net capital investment was £546 million, including £454 million (83%) invested for growth. Growth investment included the acquisitions of the 800 MW Damhead Creek power plant for £320 million and the remaining 50% of the 400 MW Brighton power plant for £71 million. Other growth investment of £63 million related primarily to our windfarm developments, notably the largest consented UK onshore windfarm project at Black Law. Development of the project continues, with completion of approximately 100 MW scheduled for autumn this year. Construction is also underway at the 30 MW windfarm at Beinn Tharsuinn and the 16 MW windfarm at Coldham.

PPM Energy s net capital investment for the year was £84 million, with £79 million (94%) of this invested for growth, primarily on new wind generation projects where build is ongoing. For 2005/06 PPM Energy has announced 574 MW of new windfarm investments, comprising 75 MW Klondike II, 100 MW Trimont, 150 MW Elk River, 150 MW Shiloh and 50% of the 198 MW joint venture Maple Ridge windfarm in upstate NewYork, which is being developed along with Zilkha Renewable Energy of Houston. Maple Ridge represents the first project in the northeastern US associated with the PPM Atlantic Renewable acquisition. PPM Energy s share of the capital investment is approximately $160 million and the 120 turbine windfarm is due to be completed this December. Once operational, all of these projects are expected to be immediately earnings enhancing.

Looking ahead, we aim to invest further capital to 2010 of some £1.7 billion in the Infrastructure Division including renewable infrastructure investment; £1.4 billion in generation and gas storage in the UK Division; and approximately £1.4billion at PPM Energy on new wind and gas storage capacity.

4 Improving Operational Performance

PacifiCorp

For the year, operating profit, excluding goodwill amortisation and the exceptional item, was lower by £78 million at £542 million (down $29 recoveries of $44 million. Deferred power cost recoveries will expire fully by the end of December 2005. Underlying retail revenues improved due to regulatory rate increases and customer growth, partly offset by lower customer usage, mainly due to the milder weather. Although the contribution from hydroelectric resources was in line with last year, it remained below expectations as a result of the unusually dry conditions. The impact of lower thermal generation availability and related increase in purchase volumes, together with higher fuel and market prices and increased load volumes, all contributed to the rise in net power costs. Operating efficiencies delivered $42 million of benefits and this more than offset adverse other net revenue and cost movements of $37 million, which increased largely as a result of higher labour-related and maintenance costs. Non-recurring items were favourable by $10 million, as the $56 million environmental provision release in the year more than offset $46 million of non-recurring items in the prior year.

Initiatives directed at improving operational efficiency included steps to significantly reduce future expected coal costs over the long-term by commencing underground coal mining in Wyoming; to aid generation efficiency by improving the management of plant overhauls and targeted capital expenditure programmes; and to deliver cost savings by renegotiating operational and service level agreements. In addition, customer service was enhanced following the streamlining and automation of activities and, in April 2005, we opened another new operations centre to facilitate the centralisation of call handling and to provide rapid responses to outages for our customers. These initiatives contributed to PacifiCorp delivering and exceeding its target of $300 million of benefits set at the time of the merger.

In February 2005, the Utah Public Service Commission granted PacifiCorp additional annual revenues of $51 million, based upon a forward-looking test year, effective from 1 March 2005. Along with other awards earlier in the year of $15 million in Washington and $9.25 million in Wyoming, this represents rate case awards in the year of approximately $75 million of additional annual revenue. On 5 May 2005, PacifiCorp filed a general rate case request in Washington for approximately $39 million that also related to increased operating costs.

PacifiCorp is also seeking to account for and recover power costs in Oregon and Washington related to the unfavourable weather conditions. These requests relate to the 2005 calendar year and are expected to be resolved early in 2006. Recovery of any weather-related costs is expected to be made at a future date. PacifiCorp has also requested power cost adjustment mechanisms (PCAMs) in Oregon and Washington. The proposed PCAMs are designed to be longer-term, on going mechanisms that pass through to customers a portion of excess power costs, or return to customers a portion of over-collected power costs. This would enable power costs included within rates to be more closely aligned with PacifiCorp s actual costs and assist in reducing earnings volatility. Discussions on possible PCAMs are also underway in Utah and Wyoming.

million to $914 million) due mainly to a net £61 million adverse translation impact from the weaker US dollar, which has been substantially mitigated at an earnings level by the benefits from our hedging policy. Retail revenue growth of $98 million was offset by both increased net power costs of $98 million and, as expected, the reduction in deferred power cost

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Regulatory returns for PacifiCorp at September 2004, the end of the last regulatory reportable period, were approximately 7% on a normalised basis compared to approximately 8% at September 2003, as the period does not include the increased revenue from the Utah general rate case settlement effective in March 2005 and the Washington general rate case outcome from November 2004.

PacifiCorp now has licenses or settlements in place regarding seven out of nine recent hydroelectric relicensing agreements. The relicensing of the Klamath River and Prospect River systems remain to be settled.

In April 2005, PacifiCorp received a magistrate judge s opinion agreeing to PacifiCorp s request to dismiss the $1 billion lawsuit filed against it in May 2004 by the Klamath Tribes. In May 2005, the Tribes filed objections to the magistrate judge s opinion and the matter is now before a district court judge.

From a customer service perspective, the US Department of Energy ranked PacifiCorp second in the nation in terms of the total number of customers purchasing renewable power and third in terms of sales volumes. In July, PacifiCorp was named best for overall customer satisfaction in a nationwide survey of commercial and industrial customers by TQS Research, an improvement from third place last year.

Infrastructure Division

For the year, operating profit increased by £23 million to £416 million, with regulated revenues higher by £13 million mainly as a result of distribution sales volume growth and favourable transmission prices, in line with allowed revenues. Underlying net costs were favourable by £14 million mainly due to a reduction in third party transmission charges and lower other net costs. This upside, together with a net £4 million increase in one-off gains, including the gain on disposal of gas assets, more than offset an £8 million increase in rates and depreciation.

In March, we accepted the new licence conditions for the Distribution Price Control Review over the next five years from 1 April 2005 and the Transmission Price Control Extension for the next two years also from 1 April 2005. The effect of the two reviews is to increase revenues by around £60 million in 2005/06 mainly due to increased revenue allowances for taxation and pension costs and also reflecting higher capital investment levels. They also introduce challenging new incentive targets which will require further improvements in operational performance in order to avoid penalties. The division has geared up across its activities to achieve and, where possible, outperform these new targets and to deliver the increased investment programme. Initiatives include deploying a greater proportion of the workforce to restore customers to the network; improved scheduling and monitoring of repairs; programmes targeted at the worst performing circuits; and a re-prioritised maintenance programme.

On 1 April 2005, the British Electricity Trading and Transmission Arrangements (BETTA) were successfully introduced with National Grid assuming operational control of the Great Britain (GB) transmission system, including balancing of generation and demand in Scotland. ScottishPower retains network ownership and all associated responsibilities including development of the network.

Two storms in January affected approximately 77,000 customers across our licence areas in Manweb and southern Scotland. Early deployment of emergency plans ensured power restoration was highly effective and we received favourable feedback from energywatch for our handling of these events.

During the year the system performance of one of our distribution businesses outperformed the regulatory targets and, subject to the annual audit of system performance data, will qualify for a one-off reward of approximately £3 million. This reward will be reflected in allowed revenue for 2005/06.

UK Division

For the year, operating profit, excluding goodwill amortisation, was higher by £79 million at £180 million. Electricity and gas margins improved by £198 million due to the growth in customer numbers combined with our investment in generation, which delivered £137 million of this increase. The effective management of our generation resource portfolio, including the benefit of our rolling commodity procurement strategy, contributed the majority of the remaining £61 million of margin growth. The substantial increase in customer numbers contributed to higher customer capture, energy efficiency and customer service costs of £45 million. Other net costs increased by £74 million, primarily due to £33 million of operating expenses relating to Damhead Creek and Brighton and higher depreciation and debt provisioning movements.

Renewable development remains a key part of our business strategy and the division is the leading developer of wind generation in the UK with approximately 3,000 MW in its renewable development pipeline, in addition to 158 MW that are operational and 142 MW under construction. We have entered into a joint venture with the Co-operative group to build a 16 MW windfarm at Coldham in Cambridgeshire. Construction is expected to be complete later this year. In March, planning determination for an 18 MW windfarm at Wether Hill in Dumfries and Galloway was given and construction will commence early in 2005/06. We have also completed trials of co-firing of biomass at our Cockenzie power station and have commenced full commercial burning. Co-firing trials have also begun at Longannet. Overall these activities demonstrate the Renewables Obligation Scheme is a successful mechanism that can deliver the Government s targets for renewable power. We maintain our support for marine renewable power through our relationship with Ocean Power Delivery, a leading developer of marine power.

As we have grown our portfolio of customers and assets, we continue to maintain a good balance between our retail demand and our generation output. We are maximising the returns from our generating plant by effectively utilising its flexibility, which is increasingly important under the new BETTA market arrangements. Our effective forward purchasing strategy for gas

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Chief Executive s Review

and coal has helped to maintain a competitive cost base for plant and customers, whilst also helping to protect us from wholesale price volatility. We are substantially covered across ourcommodity requirements for the next two years and have secured access to competitively priced low-sulphur coal from the international market, which will be delivered to our plant via our highly competitive end-to-end coal logistics deal with Clydeport.

We have successfully adapted to the new arrangements under BETTA, and we are capturing the commercial opportunities that the new arrangements present. However, we continue to have concerns with the GB transmission charging arrangements introduced with BETTA and have therefore commenced Judicial Review proceedings with respect to Ofgem s decision to approve the current GB charging methodology.

The 6 Sigma business transformation programme that was originally adopted in our supply activities was extended to our generation activities in the year and, in total, delivered revenue and cost savings of £15 million this year. In April 2005, we received a Best in Class Award at the European 6 Sigma IQ Awards in recognition of the successful delivery of a project to improve significantly customer accounts set-up time. The benefits of the improvements in our customer service provision have also been evidenced by the results seen in two customer satisfaction studies. ScottishPower came top of Datamonitor s annual survey of industrial and commercial customers and was ranked highest for price and value in J.D. Power s domestic gas market award.

PPM Energy

For the year, operating profit, excluding goodwill amortisation, increased by £22 million to £59 million (by $35 million to $98 million). PPM Energy s contribution to the group s profit before interest and tax, excluding goodwill amortisation and including results from joint ventures, was $99 million. In addition, the group s tax charge was reduced by $12 million, as a result of PPM Energy s Production Tax Credits. Gas storage margins improved by $48 million in the year, with increased contracted storagecapacity delivering $34 million of this growth and the owned facilities at Alberta and Katy, adding $14 million. Wind generation profit improved by $10 million, primarily due to investment in 2003/04 in new windfarms delivering substantial volume growth during the year. Energy management activities improved by $7 million mainly as a result of increased contributions from long-term contractual arrangements to supply electricity and gas due to higher volumes. Net operating costs required to support increased business activities and infrastructure were higher by $24 million and depreciation increased by $6 million.

PPM Energy now controls about 830 MW of operating wind energy with new developments totalling 574 MW due to beconstructed in 2005, making PPM Energy the largest US developer of renewables announced to date this year. In May 2005, PPM Energy announced plans for a 150 MW windfarm in northern California to be called the Shiloh windfarm. The Shiloh windfarm, together with the previously announced windfarms at Maple Ridge, Klondike II, Trimont and Elk River, will take PPM Energy s total wind portfolio to approximately 1,405 MW by the end of 2005, well on target toward its goal of at least 2,300 MW on-line by 2010. Approximately 90% of PPM Energy s operational windfarm output is committed under long-term contract. In December 2004, PPM Energy also acquired the northeast US wind energy developer, Atlantic Renewable Energy Corporation (now called PPM Atlantic Renewable). Including PPM Atlantic Renewable projects, PPM Energy now has approximately 9,000 MW in its renewable development pipeline, stretching from California to New York. In addition, PPM Energy has over 800 MW of thermal generation.

In May 2005, PPM Energy announced plans to expand the Waha gas storage development project in west Texas from 7.2 BCF to 9.5 BCF based on strong market demand and favourable geological results. PPM Energy also announced the acquisition of the 4.5 BCF Grama Ridge gas storage facility in New Mexico, from ConocoPhillips, which continues PPM Energy s profitable investment in gas storage assets. Including Grama Ridge, PPM Energy now has 80.5 BCF of gas storage under its ownership or control. PPM Energy intends to expand the Grama Ridge site to 6.0 BCF by the end of 2005.

5 Health and Safety

Health and safety continues to be our top priority. After our review and implementation of policies and standards, we have now undertaken two years of thorough assessments for each of our businesses. These assessments show where we have improved in sharing information and practice and where we can improve further in our ambition to have world-class health and safety performance throughout the company.

Our policy and standards reflect our determination to achieve our goal of creating a positive and productive environment, one free from injury or illness that causes no harm to our employees, customers or the public.

We have stepped up employee involvement and training, launched behavioural safety auditing and are working with our contractors to ensure they share our commitment to health and safety. We have also improved the sharing of best operational practices across our businesses.

6 Corporate Social Responsibility

During the year we have continued our commitment to building a strong business that creates benefits for customers, employees, shareholders, communities and the environment.

Our businesses and functions have been working together to identify our impacts on communities and the environment and will continue to refine further our approach to managing our

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business responsibly.

We continue to report our performance in a comprehensive and transparent manner and were again shortlisted for the ACCA sustainability reporting awards and ranked among the top 20 in Business in the Community s Corporate Responsibility Index. Our commitment to the highest standards of corporate governance was acknowledged by FTSE and Institutional Shareholder Services which placed ScottishPower third in the UK in the new Corporate Governance Index.

These achievements during a year of increased regulation and scrutiny reflect and reinforce the value of the effort of employees across the group in delivering good performance.

Two special highlights of our activity this year were helping over 10,000 young people since 1996 through ScottishPower Learning, and delivery of a national framework for youth action and engagement in the UK through the commission which I led with the Government. The Government has announced an investment of £150 million to recruit up to one million young volunteers to help build strong and cohesive communities.

7 Employees

At ScottishPower we recognise that our people are our greatest asset and employee feedback has been incorporated into the group s performance management system through our employee survey tools.

This group-wide employee survey measures how our employees feel about their working environment. The results are monitored by the Executive Team and are used as a basis for action to remove barriers to productivity and increase employee satisfaction.

We remain committed to developing talent at all levels by providing both vocational and non-vocational development activity for all employees at the work place and at home, together with tailored management development programmes.

Throughout the group we strive to recognise and celebrate the achievements of our people as we continue to build our business for the future.

8 Conclusion

In summary, we have announced the sale of PacifiCorp to MidAmerican for $9.4 billion with approximately $4.5 billion of the net proceeds to be returned to shareholders. Our full year results show profit before tax*, earnings per share* and dividends per share all up by 10%. We have set the dividend for each of the first three quarters of 2005/06 off the higher than expected base for dividends this year, at 5.20 pence per share, representing an increase of 5% from 2004/05, up from 4.2% for the first three quarters of 2004/05, compared to 2003/04. Looking ahead, we will focus our management and capital on our Infrastructure Division, UK Division and PPM Energy and we remain committed to delivering our strategy of investing for growth and improving operational performance.

Ian Russell Chief Executive

24 May 2005

** Excluding goodwill amortisation and the exceptional item*

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Business Review

1 Description of Business

Scottish Power plc (ScottishPower), a public limited company registered in Scotland, is an international energy company listed on both the London and New York Stock Exchanges. Through its operating subsidiaries, the company provides in excess of 6.7 million electricity or gas services to homes and businesses across the UK and in the western US. It provides electricity generation, transmission, distribution and supply services in both countries. In addition, the company s North American activities extend to coal mining and gas storage, including gas facilities in western Canada, Texas and New Mexico. In Great Britain, ScottishPower also stores and supplies gas. In the year to 31 March 2005, the sales revenues of the group were £6.8 billion ($12.9 billion).

ScottishPower was created upon privatisation in 1991 and then developed by both organic growth and strategic acquisitions in the British electricity, gas and telephony markets-and through its November 1999 merger with PacifiCorp in the US. Following the group s redefinition as an energy business in 2001, it exited or disposed of non-strategic activities in the US and UK and demerged its UK telecommunications and internet business, Thus, to the company s shareholders.

Since 2002, ScottishPower has focused on investing for growth and improving operational performance in its energy businesses. Following a strategic review of the scale and timing of capital investment requirements, opportunities for growth and improving operational performance and the likely profile of returns from the group s businesses, developed with no material changes to its current operating plans, management structures or boards.

Strategic Context

ScottishPower s strategy is to focus its management and capital on the further development of the three continuing businesses, which the group judges to have attractive opportunities for continued growth through capital investment and improved operational performance. The regulated UK wires business provides a base for steady growth through consistent investment and proven skills in operational and regulatory management. In the competitive businesses where the group s management believes that it can deploy local market knowledge and employee skill advantages, it seeks to grow its market share and to enhance margins through the integration of generation, energy management and customer services, underpinned by strong operational performance. The aim is consistently to improve operational performance whilst investing to support the organic growth and development of the businesses. The group expects growth to arise from investment in new generation, networks and gas storage assets. ScottishPower will also seek to accelerate its organic growth through competitive market share gains and selective acquisitions of smaller operations that complement the group s business. Shareholder value is expected to be created through an investment programme assessed on a risk-adjusted returns basis and aiming to retain an A category credit

ScottishPower has entered into a binding agreement for the sale of PacifiCorp to MidAmerican for $9.4 billion. Regulatory approvals of the sale are expected to be forthcoming within 12 to 18 months. Prior to sale, it is envisaged that PacifiCorp will be managed and

rating for the group s principal operating subsidiaries. Individual investments in the continuing regulated business are expected to achieve at least the allowed rate of regulatory returns, whilst those in the competitive businesses are targeted to achieve returns of at least 300 basis points above each division s weighted average cost of capital.

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The group currently operates through four businesses, see chart above.

- Ø PacifiCorp
- Ø Infrastructure Division
- Ø UK Division
- Ø PPM Energy

In each of the US and the UK, there is one business operating under regulation and one in competitive market conditions. Each business is clearly focused on its strategic priorities.

In the US, PacifiCorp operates as a regulated electricity business and the competitive energy business is PPM Energy. Both are subsidiaries of PacifiCorp Holdings, Inc. (PHI) a non-operating, US holding company, itself an indirect wholly-owned subsidiary of ScottishPower. PHI is also the parent company of PacifiCorp Group Holdings which owns the shares of subsidiaries not regulated as domestic electricity providers, including PacifiCorp Financial Services, Inc.

In the UK, the regulated Infrastructure Division operates electricity transmission and distribution subsidiaries of the wholly-owned UK holding company Scottish Power UK plc (SPUK). Other subsidiaries comprise the group s competitive energy business, the UK Division, covering its generation assets in the British Isles, its commercial and energy management activities and its energy supply business units.

2 PacifiCorp

In November 1999, PacifiCorp and ScottishPower completed a merger under which PacifiCorp became an indirect subsidiary of ScottishPower. Following the merger, PacifiCorp focused on its electricity businesses in the western US and embarked upon a programme of efficiency improvements. Pending completion of its proposed sale to MidAmerican, PacifiCorp is expected to maintain this focus, without material changes to its operating plans, management structures or boards.

Principal Business Activities

PacifiCorp is a regulated electricity company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. As a vertically-integrated electricity business, PacifiCorp owns or has contracts for fuel sources, such as coal and natural gas, and uses these fuel sources, as well as wind, geothermal and water resources, to generate electricity at its power plants. This electricity, together with electricity purchased on the wholesale market, is transmitted over a grid of approximately 15,530 miles of transmission lines throughout PacifiCorp s six-state region and is then transformed to lower voltages and delivered to end-use customers through the approximately 58,360 miles of PacifiCorp s distribution system. PacifiCorp conducts its retail electricity utility business as Pacific Power and Utah Power, and engages in electricity sales and purchases on a wholesale basis under the name PacifiCorp. The subsidiaries of PacifiCorp support its electricity utility operations by providing coal mining facilities and services and environmental remediation.

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Business Review Description of Business

The western US energy market is experiencing growth in demand due to both increased customer numbers and underlying load growth. Through the continual review and updating of its Integrated Resource Plan (IRP), PacifiCorp aims to maintain a balanced load and resource position and has hedged its forecast load and resource balance and price exposure for summer 2005, when demand is expected to be supported by the commissioning of the first phase of the 525 megawatt (MW) Currant Creek plant in Utah. PacifiCorp also continued to invest in support of network safety, reliability and high-level performance, including targeted investments in areas of high demand growth.

Retail Electricity Sales

PacifiCorp serves approximately 1.6 million retail customers in service territories aggregating about 136,000 square miles in portions of six western states. The geographical distribution of PacifiCorp s retail electricity operating revenues for the year ended 31 March 2005 was Utah, 41%; Oregon, 29%; Wyoming, 14%; Washington, 8%; Idaho, 6%; and California, 2%.

The PacifiCorp service area s diverse regional economy mitigates exposure to economic fluctuations. In the eastern portion of the service area, mainly Utah, Wyoming and southeastern Idaho, customer demand peaks in the summer when cooling systems and irrigation are heavily used. The principal industries are manufacturing, health services, recreation and mining or extraction of natural resources. In the western part of the service territory, mainly consisting of Oregon, southeastern Washington and northern California, customer demand peaks in the winter months due to heating requirements and the economy generally revolves around agriculture and manufacturing, with forest products, food processing, high technology and primary metals being the principal industries. During 2004/05, no single retail customer accounted for more than 2% of PacifiCorp s retail electricity revenues and the 20 largest retail customers accounted for 13% of retail electricity revenues. Trends in energy sales by class of customer are set out in Tables 4 and 5 (page 34).

PacifiCorp serves some areas of rapidly changing population size and economic activity. Strong growth in the number of residential customers in Utah over recent years and increasing numbers of central air conditioning systems are contributing to a faster summer peak growth. Commercial sales are positioned for growth in the eastern portion of the service territory, particularly Utah, because of strong population and economic viability and through Utah s central role in the manufacture, distribution and delivery of goods to surrounding western states. Wyoming is continuing to experience increasing industrial activity in its energy-related sectors, with rising exploration and rig counts suggesting a positive trend in PacifiCorp s future sales to the industrial sector in the state. Oregon has returned to pre-recessionary conditions statewide and PacifiCorp serves a number of communities showing higher than average levels of growth in that state. These factors suggest the likelihood of an increasing pace of economic development and recovery across PacifiCorp service territories.

For the five years to 31 March 2010, the underlying annual growth in retail megawatt hour (MWh) sales in PacifiCorp s franchise service territories is estimated to be in the range of 2.2% to 3.3%, dependent upon factors such as economic growth, changes in customer numbers, weather, the potential effects on demand resulting from conservation efforts and changes in price. If energy prices increase in the region, demand growth over the region may slow.

Power Production and Fuel Supply

PacifiCorp owns or has interests in generating plants with an aggregate plant net capability of 7,981 MW, see Table 1 (page 33). During 2004/05, approximately 74% and 5% of PacifiCorp s energy requirements were supplied by its thermal and hydroelectric generation plants, respectively. The remaining 21% was obtained primarily through purchased power. The share of PacifiCorp s energy requirements generated by its own plants will vary from year-to-year and is determined by factors such as planned and unplanned outages, availability and price of coal and natural gas, precipitation and snowpack levels, environmental considerations and the market price of electricity. PacifiCorp will make use of existing long-term purchase contracts, including those covering some 65 MW of wind power, and expects to choose appropriate cost-effective resources to meet the balance of its customer demand through new long- and short-term purchase arrangements.

The IRP, under which PacifiCorp seeks to manage future generation needs and meet environmental objectives, is reviewed and updated every two years. The latest IRP update was filed in January 2005 and indicates that projected growth rates and contract expirations imply a need for approximately 2,800 MW of additional resources by 2015. These estimates are subject to ongoing review and possible revision. PacifiCorp is continuing to develop plans to meet this resource requirement through a mix of new thermal generation, load control programmes, energy conservation programmes and the renewable resources first identified in the 2003 IRP.

Large resource procurement action items from PacifiCorp s IRP are pursued through the Requests for Proposals (RFP) process which seeks to identify PacifiCorp s future resource mix though a programme coordinated with stakeholders in the six states it serves. From the first of the RFPs, in 2003, PacifiCorp determined that the construction of a new 525 MW gas-fired plant in Utah would be the lowest risk and most economical 2004/05 resource category choice to meet future generation needs. This plant, known as Currant Creek, has been fully authorised by the Utah authorities, is currently commissioning and is expected to come on-line in two phases over 2005 and 2006. In 2004, PacifiCorp chose Summit Vineyard LLC for the construction of a 534 MW Lake Side

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Power Plant near Salt Lake City, Utah. The Utah Public Service Commission (UPSC) has granted all the permissions required to construct and operate the Lake Side Power Plant, and PacifiCorp is scheduled to begin operating the plant in May 2007. In May 2005, PacifiCorp entered into a 65 MW power purchase agreement, to take effect prior to January 2006, for the output of a windfarm located in southeastern Idaho. Further negotiations continue to bring into use some 1,100 MW of new renewable resources across the PacifiCorp service territories over the period to 2010, as a result of the February 2004 RFP.

At 31 March 2005, PacifiCorp had 259 million tons of recoverable coal reserves that are mined by PacifiCorp s mining affiliates and are available to nearby PacifiCorp-operated generation plants, see Table 2 (page 33). During 2004/05, these mines supplied some 29% of PacifiCorp s total coal requirements. Coal is also acquired through long- and short-term contracts. Thirteen long-term coal contracts accounted for 70% of the overall 2004/05 requirements. The contract terms range from one to 18 years. PacifiCorp has also entered into fixed-price and index-price natural gas contracts to meet the forecasted needs of its existing natural gas-fired electricity generation plants to the end of calendar year 2006 and to secure approaching 80% of its forecasted calendar year 2007 gas supply needs, inclusive of the Currant Creek and Lake Side projects.

Wholesale Sales and Purchased Electricity

In addition to its base of thermal, renewable and hydroelectric generation assets, PacifiCorp uses a mix of long-term, short-term and spot-market purchases to balance its retail load and wholesale obligations. PacifiCorp enters into wholesale purchase and sale transactions to provide hedges against periods of variable generation or variable retail load. Generation varies with the level of outages or transmission constraints and retail load varies with the weather, distribution system outages, customer trends and the level of economic activity. During the year ended 31 March 2005, some 21% of PacifiCorp s energy requirements were supplied by electricity purchased under short- and long-term arrangements, compared with some 22% for the year ended 31 March 2004. PacifiCorp s wholesale transactions are integral to its retail business, providing for a balanced and economically hedged position and enhancing the efficient use of its generating capacity over the long term. PacifiCorp s transmission system is available for common use consistent with open access regulatory requirements and connects with market hubs in the Pacific Northwest to provide access to what is normally low-cost hydroelectric generation and also to the southwestern US, which provides access to normally higher-cost fossil-fuel generation.

Under the requirements of the Public Utility Regulatory Policies Act of 1978, PacifiCorp purchases the output of qualifying facilities constructed and operated by entities that are not public utilities. During 2004/05, PacifiCorp purchased an average of 139 MW from qualifying facilities, compared to an average of 119 MW in 2003/04.

3 Infrastructure Division

Three wholly-owned subsidiaries of SPUK SP Transmission Limited, SP Distribution Limited and SP Manweb plc are the asset-owner companies holding the group s UK regulated assets and transmission and distribution licences. A further wholly-owned subsidiary of SPUK SP Power Systems Limited (PowerSystems) provides asset management expertise and conducts the day-to-day operation of the networks.

Principal Business Activities

The asset-owner companies act as an integrated business unit to concentrate divisional expertise on regulatory issues and investment strategy. PowerSystems implements work programmes commissioned by and agreed with the asset-owner business. Strict commercial disciplines are applied at the asset owner-service provider interface, with PowerSystems operating as a contractor to the transmission and distribution business unit. An integrated senior management team within the Infrastructure Division applies the benefits of growing expertise in asset ownership, financing and operational service provision to the management of the group s regulated networks businesses in both the UK and the US.

Transmission and Distribution

ScottishPower owns a substantial UK electricity transmission and distribution network which extends to approaching 112,000 km, with some 65,000 km of underground cables and 47,000 km of overhead lines, comprising both the distribution system to customers in its two authorised areas and, in Scotland, its high-voltage transmission system (132 kilovolt (kV) and above, including those parts of the England-Scotland interconnector which are in its Scottish authorised area). Table 8 (page 35) shows key information with respect to the division s transmission and distribution services in 2004/05 which were operated under licences issued by the Gas and Electricity Markets Authority (the Authority) and held by the transmission and distribution businesses, which were entitled to charge for the use of the systems on terms approved by the Authority under various price control formulae. From 1 April 2005, operation but not ownership of the ScottishPower transmission system passed to a single, Great Britain-wide system operator. This development is described further on

page 76.

The management focus of the transmission and distribution business is to outperform allowed regulatory returns from the

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Business Review Description of Business

provision of efficient, coordinated and economical networks that are open to licensed users on a non-discriminatory basis (in order to facilitate competition in generation and supply) and operated to approved standards of safety and reliability. The distribution business price controls for the five years from 1 April 2005 and the transmission price controls for the two years from 1 April 2005 were agreed with the Office of Gas and Electricity Markets (Ofgem) in December 2004 and present challenges for the division but also opportunities to enhance returns through a revised package of performance-incentive measures. Ofgem has also agreed that the division can move ahead with the first phase of investments in network development to support the UK Government s planned expansion of renewable generation.

The income derived from the distribution business is dependent on the demand for electricity by customers in the authorised areas. Demand for electricity is affected by such factors as growth and movements in population, social trends, economic and business growth or decline, changes in the mix of energy sources used by customers, weather conditions and energy efficiency measures. Tables 9 and 10 (page 35) set out the demand in gigawatt hours (GWh) by customer type within the broadly stable levels of electricity transported over the distribution systems in the ScottishPower and Manweb home areas during the five most recent financial years.

Asset Management

Within the PowerSystems business unit, the focus continues to be on cost-effectiveness and service quality improvement. Its principal business activities involve the construction and refurbishment of the ScottishPower transmission and distribution systems, their maintenance and related fault repair. PowerSystems acts as the major service provider to the ScottishPower distribution businesses and as the primary customer contact agent for network-related matters. PowerSystems continues to focus strongly on the efficient delivery of these services under contract. The regulatory framework provides financial incentives to improve network performance and customer satisfaction. PowerSystems is focused on maximising the financial benefit to be obtained from these incentives over the course of the recently renewed price control period.

Some 25% of the division s investment programme is devoted to organic growth areas such as new customer connections and network reinforcement. PowerSystems has continued to maintain a joint venture with Alfred McAlpine Utility Services Limited, called Core Utility Solutions Limited, to take advantage of the opportunities presented by the requirement for competitive provision of connections to distribution networks.

4 UK Division

The UK Division operates in gas and electricity markets which became fully competitive with the ending of residual price controls on 31 March 2002; although Ofgem continues to enforce licence conditions and regulate quality of service. The division comprises five wholly-owned subsidiaries: ScottishPower Generation Limited owns and operates the group s power stations and other generation assets in the British Isles and holds the group s generation licence; ScottishPower Energy Management Limited is responsible for commercial running of the power stations including scheduling and fuel purchasing, for managing retail economics and pricing, and for managing commodity risk through buying and selling wholesale energy via ScottishPower Energy Management (Agency) Limited; ScottishPower Energy Retail Limited is the gas and electricity supply company and holder of the group s supply licences, managing pricing, selling, billing and receipting for gas and electricity supply to both business and domestic customers and dealing with enquiries arising in the course of this business; and SP Dataserve Limited is the data management and metering company, managing the data processes that underpin customer registration through to billing and settlement.

The divisional management team oversees activities across the energy value chain, maximising value from a diverse generation portfolio through to a national customer base of over 5.1 million, via an integrated commercial and energy management activity that acts to balance and hedge energy needs. In 2004/05, wholesale energy prices were high by historic standards although, in light of the emphasis on a market-based framework for energy policy set out by the UK Government in February 2003, it seems likely that prices will tend to increase further towards the long run marginal cost of gas-fired generation, augmented by the developing impact of carbon trading. As an active market participant, the division engages fully in regulatory and contractual debate and in the consultation processes following the UK Government s review of energy policy. In the meantime, the division aims to leverage the benefits of its flexible generation asset base and commercial operations to deliver sustained earnings through improved business processes and customer service and to develop its position in renewable generation and other aspects of the emerging market for environmental instruments.

Principal Business Activities

The UK Division operates ScottishPower s generation assets in the British Isles, manages the company s exposure to the UK wholesale electricity and gas markets and is responsible for energy supply, the sales and marketing of electricity and gas to customers throughout Great Britain, together with the associated customer registration, billing and receipting processes and handling enquiries in respect of these services.

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Power Plant Portfolio, Fuel Strategy and Generation Sales

The UK Division operates some 6,200 MW of generating capacity, see Table 7 (page 35) comprising coal, gas, hydroelectric and wind power generation assets, giving the division a particularly flexible portfolio. Acquisition of an additional 1,000 MW of thermal generation capacity took place during 2004/05 at prices below the group s view of new-build cost. The 2003 restatement of the public policy emphasis on renewable generation, and the extension to 2015 of the Renewables Obligation targets, provide the context for the continued expansion of the windfarm business. At 31 March 2005, the UK Division had operational windfarms totalling 158 MW, 142 MW under construction, planning applications for a further 650 MW and environmental assessments begun on around 550 MW of further potential sites to ensure that the company target of 10% of supply from renewables by 2010 is met.

ScottishPower s fuel purchasing strategy is based upon the objective of achieving competitive fuel prices while balancing the need for security and flexibility of supply. The major components of the fuel portfolio are coal and gas, both fuels being sourced through a combination of long-term contracts and shorter-term trading. The division has three long-term contracts with terms of greater than five years for supply from major gas fields. The manner in which the division builds protection against fluctuating fuel prices is described further in the Energy Price and Volume Risk Management section on page 76.

Generation plant is despatched economically and output is managed to maximise value, including optimising the position in the balancing market. In 2004/05, some 18 terawatt hours (TWh) were despatched, both to contribute towards the approximately 35 TWh of retail and wholesale demand provided by the division and to maintain export volumes through the interconnectors to England & Wales and to Northern Ireland.

Energy Management and Commercial Arrangements

In addition to scheduling its own generation capacity and managing the long-term bulk gas contracts, the UK Division, through its energy management operation, uses medium- and short-term contractual arrangements to complete its energy balancing of the whole portfolio of assets and customers. This involves both purchases and sales of electricity and gas, including selling in Scotland and, through the interconnectors, to England & Wales and to Northern Ireland. A Great Britain-wide wholesale electricity market was introduced on 1 April 2005 through the British Electricity Trading and Transmission Arrangements (BETTA). BETTA is expected to have only a modest impact on end-user prices but provides a wider opportunity for the sale of the group s generation output and the deployment of its proven skills in providing market balancing services. End-user electricity and gas prices are generally set over the long-term, whereas wholesale contracts have varying terms and short-term and spot prices vary markedly by time of day, week and year. Through its activities in the electricity, gas and coal markets, ScottishPower s energy management business seeks to secure competitive advantage for the UK Division through hedging and optimising its position across the energy value chain, from fuel procurement and plant despatch through to retail pricing, continuously evaluating and managing risk exposure. This process is described further in the Energy Price and Volume Risk Management section on page 76.

ScottishPower s Hatfield Moors gas storage site enhances the flexibility of the division s energy management position, both in meeting peak demands of supply customers and responding to the volatility of gas prices between midweek and weekends. In addition, the bulk gas contracts allow the gas to be sold out or used in the division s power stations, giving yet more flexibility. Plans for a further 6 billion cubic feet (BCF) gas storage facility at Byley, Cheshire have been given planning approval.

Energy Supply

Since September 1998 when, under the provisions of the Electricity Act, competition was extended to residential electricity customers, a strategic focus of the ScottishPower energy supply business has been the defence of its core markets, residential and small business customers in the ScottishPower and Manweb home areas, whilst seeking profitable additional business outside these historical regional boundaries. Retention of home area residential customers stands at 61% whilst innovative product offerings, targeted sales efforts and wide-ranging sales channels (including strategic marketing alliances such as the partnership with Sainsbury s, a number of other affinity deals across a wide range of market sectors and the use of e-commerce channels) have helped develop a Britain-wide customer base which now stands at over 5.1 million energy accounts. The business improvement programme introduced in 2001 continues to drive improvements across the retail supply business and has helped to deliver increased direct debit penetration and reduced customer churn rates in addition to cost benefits in areas such as billing, debt and customer registration business processes.

Metering and Data Management

In the competitive energy market SP Dataserve Limited (Dataserve) operates end-to-end process and data management in order to maximise efficiencies in the provision and control of registration and metering data for ScottishPower and other agency arrangements. Data management covers the establishment of new customers, maintenance of existing customers and accuracy of energy settlement. To effectively manage gas and electricity customers, ScottishPower Energy

Retail Ltd has continued to contribute to improvements in billing performance through the management of its metering agents, who are responsible for the provision of much of the data.

5 PPM Energy

PPM Energy, the group s competitive US energy business, is a fast-growing energy provider, with operating assets in ten US states and in Canada. Its diverse portfolio, focus on wind power and moderate risk approach all position PPM Energy for expected earnings growth. PPM Energy commenced substantive operations in 2001 and is growing through a strategic focus on clean energy: concentrating on renewable power, natural gas storage and hub services and gas-fired generation.

Principal Business Activities

PPM Energy s principal assets are thermal and renewable generation resources and natural gas storage facilities. PPM Energy seeks to create value by securing quality assets at strategic locations and by locking in value through long-term contracts with creditworthy customers. Integration of plant operations, contract dispatch and energy management add additional value. The optimisation benefits come from displacing plant operations with low-priced electricity purchases, and selling the displaced gas or placing it in storage, as well as using transmission and contract delivery flexibility to manage locational price differences in both gas and electricity. PPM Energy aims to leverage the benefits of its flexible asset base and contracts to extract value across the gas and electricity sectors.

Power Production and Wholesale Sales

PPM Energy has more than 1,600 MW of operating assets currently under its ownership or control and, of that total, PPM Energy has full economic interest in 1,368 MW, see Table 6 (page 34). PPM Energy balances its supply and sales, selling a substantial amount of its supply forward under long-term contracts. In its electricity business, PPM Energy serves a wide variety of wholesale energy customers including municipal agencies, public utility districts and investor-owned utilities. These customers are primarily located in wholesale energy markets served by the 1.8 million square mile Western Electricity Coordinating Council service territories in the western US and the Mid-Continent Area Power a project pipeline of more than 500 MW in the northeast US, planned to be operational between 2005 and 2010. In April 2005, PPM Energy announced that, with its joint venture partner, Zilkha Renewable Energy of Houston, it is to build and own the 198 MW Maple Ridge Windfarm in New York. On 23 May 2005, PPM Energy also announced plans for a 150 MW windfarm in northern California, to be called the Shiloh windfarm. When projects previously announced come on-line in 2005 (the 75 MW Klondike II windfarm in Oregon, the 100 MW Trimont windfarm in Minnesota, the 150 MW Elk River windfarm in Kansas, the 150 MW Shiloh windfarm in California and 50% of the 198 MW joint venture Maple Ridge windfarm in upstate New York), PPM Energy will have approximately 1,405 MW of wind power under its ownership or control. PPM Energy remains on target to deliver its goal of 2,300 MW of renewables by 2010.

Gas Storage and Hub Services

PPM Energy s two major gas storage facilities are in Alberta, Canada and in Katy, Texas. Each is connected into substantial pipeline networks serving well-diversified customer bases under firm, long- and short-term contract arrangements. In addition to the 46 BCF of gas storage capacity under the group s ownership, PPM Energy increased its available gas storage capacity by 30 BCF through contracting for capacity in third-party storage facilities in western Canada, Texas and California. PPM Energy also has begun development of a 9.5 BCF high-deliverability salt cavern gas storage project in west Texas and acquired the 4.5 BCF Grama Ridge gas storage facility in New Mexico.

6 Group Employees

US Businesses PHI and its subsidiaries had 6,934 employees at 31 March 2005, of which PacifiCorp and its subsidiaries had 6,656 and PPM Energy and its subsidiaries 278. Approximately 57% of the employees of PacifiCorp and its mining subsidiaries are covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the International Brotherhood of Boilermakers and the United Mine Workers of America. In the company s judgement, employee relations in the US businesses are satisfactory.

UK Businesses ScottishPower and its UK subsidiaries had 9,208 employees, at 31 March 2005. Of these, 3,541 were employed in the Infrastructure Division and 5,667 in the UK Division. Approximately 56% of employees in the UK are union members, and 83% are

Pool service territories in the upper midwest US, although PPM Energy s operations are now being extended into the northeastern US.

covered by collective bargaining arrangements. In the company s judgement, employee relations in the UK businesses are satisfactory.

Wind Power

PPM Energy is a leading provider of wind energy in the US. In December 2004, PPM Energy acquired the wind energy developer, Atlantic Renewable Energy Corporation (now known as PPM Atlantic Renewable). This brings into the group

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Human Resources Strategy

The group s human resources (HR) strategy was approved by the Board in July 2002 and aims to ensure that the group s businesses achieve superior results through the high performance of their employees. In 2004/05, in support of this group HR strategy, a combined UK and US HR strategy has been developed to take account of the implications of the group HR strategy.

The management of health and safety in ScottishPower is based on a Group Health & Safety Framework introduced in January 2004 and overseen by the Group Health & Safety Executive Committee, composed of US and UK members who meet on a quarterly basis. There are 12 key Health & Safety Standards that are used to provide regular assurance to the Board, to the Executive Team and to employees that health and safety is managed effectively and in line with stated policy. Challenging targets are set each year for both lost time accident rates and leading indicator metrics, covering progress against the Group Health & Safety Standards and building on the baseline assessments carried out in 2003/04.

Employee Consultation

An annual survey is conducted across all businesses to provide a measure of employees perception of the company s direction and their sense of empowerment, value, training and development and of manager communication. Survey results are shared with all employees, reviewed by the Executive Team and used in each business to set targets and action plans for the following year. In addition, individual businesses use surveys and other tools to understand the issues that fall within their specific areas of responsibility and regular consultation takes place using a variety of means, including monthly team meetings, team managers conferences, business unit road shows, safety committees, presentations and employee magazines. The group believes that an important element of a positive working experience is stable employee and industrial relations, it recognises the legitimacy of trade union involvement and has formal agreements in place to foster open, two-way communication and consultation. Positive relationships and ongoing liaison with employees and their representatives are seen as contributing significantly to achieving the performance objectives of the businesses.

Further details of group workplace policy and performance can be found in the ScottishPower Environmental and Social Impact Report and the Workplace Performance Report. Both are available on the ScottishPower website. The company also operates a number of all-employee share plans (see page 98).

7 Group Environmental Policy

ScottishPower recognises the need to embrace a wider role in society and to engage fully with shareholders, employees, communities, customers, regulators, legislators and other opinion formers. It aims to do this transparently, through an international framework, to ensure that key principles are translated into action. This framework comprises overall international visionary goals; and specific goals for the US and UK. Performance towards meeting these goals is tracked through carefully chosen Key Performance Indicators, closely related to business unit objectives. Hence, it must strive to achieve a balance between various needs including securing energy supply now and into the future, keeping energy affordable and minimising its impact on the environment.

Public policy frameworks in the US and UK have common elements, particularly in using market instruments for air quality regulation and supporting renewables and energy efficiency measures. The group continues to develop specific policies to respond to these regulatory challenges, aiming to grow its business sustainably in new energy markets, to invest in renewables and clean-coal technology and to ensure that customers benefit from innovations in energy efficiency. It also aims to manage existing coal-fired assets responsibly, applying appropriate abatement technologies to reduce its environmental footprint whilst supporting security of supply and affordability of power for its customers. The lines of accountability for environmental policy are focused through the policy making Energy and Environment Committee, chaired by the Chief Executive and with direct reporting lines to ScottishPower s Executive Team.

Further details of group environmental policy and performance can be found in the ScottishPower Environmental and Social Impact Report and the Environmental Performance Report. Both are available on the ScottishPower website.

8 Community Impact

In order to encourage comparability, the group uses the London Benchmarking Group (LBG) model to evaluate its community support activity across the group. The LBG model is a standard for community reporting currently adopted by 99 leading UK companies. It endeavours to provide consistency and comparability across companies and to account for the total impact on communities, rather than charitable contributions alone. ScottishPower s use of the model is reviewed each year by the LBG to help ensure the evaluation principles are correctly and consistently applied.

In 2003, the LBG Model was expanded to include a

category for mandatory contributions (which incorporates Community contributions or activities undertaken as a result of the requirements of law, regulation or contract) to account for the overall impact a company and its operations has on communities. These are reported separately from voluntary contributions. ScottishPower is reviewing changes to the model, has ensured all mandatory or regulated spend is excluded from its currently reported community support contributions, and has begun tracking to enable it to report the full community impact of its business activities in future years.

During 2004/05, ScottishPower companies contributed £4.1 million in community support activity, of which £1.5 million was contributed to registered charitable organisations. The total incorporated £557,000 categorised by the LBG model as charitable gifts, £2.6 million of community support activity categorised as community investment and £1.0 million categorised as commercial initiatives in the community given in cash, through staff time and in-kind donations by the company s US and UK operations. An additional £1.2 million of charitable support was made through the PacifiCorp Foundation for Learning, which is fully endowed by ScottishPower companies.

Further details of group community engagement policy and performance are summarised in the ScottishPower Environmental and Social Impact Report and the Community Performance Report. Both are available on the ScottishPower website.

9 Description of the Company s Property

US Businesses The US properties consist primarily of generating facilities, electricity transmission and distribution facilities, coal mines, gas storage facilities and a number of office facilities. Substantially all of PacifiCorp s electricity property is subject to the lien of PacifiCorp s Mortgage and Deed of Trust.

PacifiCorp owns or has an interest in 51 hydroelectric generating plants. These have an aggregate plant net capability of 1,155 MW. It owns or has interests in 16 thermal electric generating plants with an aggregate plant net capability of 6,793 MW. PacifiCorp jointly owns one wind power generating plant with plant net capability of 33 MW. Table 1 (page 33) sets out key aspects of PacifiCorp s existing generating facilities. These generating facilities are interconnected through PacifiCorp s own transmission lines or by contract through the lines of others. Substantially all of PacifiCorp s generating facilities and reservoirs are managed on a coordinated basis to obtain maximum load carrying capability and efficiency and to manage river systems and preserve fish stocks. Portions of PacifiCorp s almost 74,000 miles of transmission and distribution networks are located, by franchise or permit, upon public lands, roads and streets and, by easement or licence, upon the lands of other third parties. Table 3 (page 34) sets out further information regarding the PacifiCorp networks.

PacifiCorp s coal reserves are described in Table 2 (page 33). Most are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have multi-year terms that may be renewed or extended and require payment of rentals and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

PPM Energy has more than 1,600 MW of operating assets currently under its ownership or control and, of that, PPM Energy has full economic interest in 1,368 MW, see Table 6 (page 34). The majority of PPM Energy s capacity (606 MW of wind power contracted for a period of 25 years and 237 MW of thermal power contracted for a period of 30 years) comes from long-term agreements while 525 MW comes from outright ownership of six wind plants and two thermal plants. PPM Energy s windfarms are on land owned or leased for 25 years or more. PPM Energy also manages ScottishPower-owned gas storage facilities in Alberta, Canada and owns facilities in Texas and New Mexico, representing an overall total of 50.5 BCF of gas storage capacity.

UK Businesses The UK properties consist of generating stations, transmission and distribution facilities and certain non-operational properties in which the company holds freehold or leasehold interests.

ScottishPower owns seven power stations in Scotland (five of which are operational) and four in England. It also owns three windfarms in Northern Ireland, five in Scotland, and one in the Republic of Ireland. In addition, the company has joint venture interests in three windfarms, two of which are in England and one in Wales. All generation plant is owned by the group, with the exception of the non-operational Methil power station, which is held on a ground lease that expires in 2012, and the windfarms which are generally held on ground leases of at least 25 years duration. See Table 7 (page 35) for further details of operational generation assets.

At 31 March 2005, the UK transmission facilities included approximately 4,000 circuit km of overhead lines and underground cable operated at 400 kV, 275 kV and 132 kV. In addition, the distribution facilities included approximately 108,000 circuit km of overhead lines and underground cable at voltages operating from 33 kV to 0.23 kV. The group holds either permanent rights or wayleaves which entitle it to run these lines and cables through private land. See Table 8 (page 35) for further details.

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10 Description of Legislative and Regulatory Background

As a public limited company (plc), Scottish Power plc is subject to the UK Companies Acts and is also registered as a holding company under the US Public Utility Holding Company Act of 1935, as amended, (1935 Act) which is administered by the United States Securities and Exchange Commission (SEC). Hence, Scottish Power plc, PacifiCorp and other subsidiaries are subject to regulation unless specific subsidiaries or transactions are otherwise exempt by SEC rules or orders. SPUK and its subsidiaries are generally exempt from regulation under the 1935 Act because SPUK is a foreign utility company as defined in the 1935 Act.

ScottishPower s UK operations are subject to such European Union (EU) Directives as the UK Government brings into effect, specifically, the EU energy liberalisation directives and EU prohibitions on anti-competitive agreements and the abuse of a dominant position (implemented through the Competition Act 1998, which came into effect from 1 March 2000) and also to the provisions of the Electricity Act 1989 (Electricity Act) as amended by the Utilities Act 2000 (Utilities Act) and other legislation including the Energy Act 2004 (Energy Act). The Utilities Act introduced a legal framework for energy company licences based on standard, UK-wide conditions and, taken together with requirements of the Department of Trade and Industry (DTI) and licence changes introduced by the Regulators, defines the regulatory framework within which SPUK and its subsidiaries must operate.

A summary of the more specific legislative and regulatory background to the operations of the group s businesses is set out below.

11 US Business Regulation

PacifiCorp is subject to the jurisdiction of the public utility regulatory authorities in each of the states in which it conducts retail electricity operations. These authorities regulate various matters including prices, services, accounting, the allocation of costs by state, issuance of securities and other matters. PacifiCorp is a licensee and a public utility as those terms are used in the Federal Power Act (FPA) and is, therefore, subject to regulation by the Federal Energy Regulatory Commission (FERC) as to accounting policies and practices, certain prices and other matters.

Because PPM Energy does not conduct retail electricity operations, it is not subject to the same state public utility commission regulation as PacifiCorp. However, certain of its wholesale activities are regulated by the FERC and the state commissions impose certain limitations on affiliate transactions. In addition, PPM Energy s gas storage activities in Texas are subject to regulation by the FERC and the Texas Railroad Commission and those in Canada are subject to regulation by the Alberta Energy and Utilities Board.

FERC Issues

California Refund Case

PacifiCorp is one of a number of parties to a FERC investigation of potential refunds for energy transactions in California during past periods of high-energy prices. In 2001/02, it established a provision of $17.7 million for these potential refunds and has subsequently fully provided in the amount of $5 million for defaults in receivables from certain counterparties. PacifiCorp s ultimate exposure to refunds is dependent upon any final order issued by the FERC in this proceeding.

FERC Show-Cause Orders

In August 2003, PacifiCorp and the FERC staff reached a resolution on the FERC order to show why various parties behaviour during the California energy crisis did not constitute manipulation of the wholesale electricity market. Under the terms of the settlement agreement, PacifiCorp denied liability and agreed to pay a nominal amount of $67,745 in exchange for complete and total resolution of the issues raised relating to it in the FERC s show-cause order. The FERC issued its final order approving the settlement in March 2004. Several market participants have requested a rehearing of the FERC s approval and a decision on the rehearing request is pending.

Northwest Refund Case

In June 2003, the FERC terminated its proceeding in this case, concluding that ordering refunds would not be an appropriate resolution of the issues relating to wholesale spot-market bilateral sales in the Pacific Northwest between 25 December 2000 and 20 June 2001. In November 2003, the FERC issued its final order denying a requested rehearing. Several market participants have filed petitions in the court of appeals for review of the FERC s final order but any decision from the court of appeals is not expected to have a material impact on the group s consolidated results or financial position.

Federal Power Act Section 206 Case

In November 2003, the FERC also issued its final order denying a rehearing of PacifiCorp s request for recovery of excessive prices charged under certain wholesale electricity purchases scheduled for delivery during summer 2002. PacifiCorp s appeal for review of the FERC s final order is before the US Court of Appeals for the Ninth Circuit. Court briefs from interested parties were filed in March 2005.

FERC Market Power Analysis

PacifiCorp and PPM Energy are authorised by the FERC to charge market-based rates for sales of wholesale energy and

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Business Review Description of Legislative and Regulatory Background

capacity. Under the FERC s current policy, market participants must demonstrate that they do not possess market power and are required to submit a market power analysis every three years. The analysis must be applied to all affiliated entities on a combined, or aggregate, basis thus PacifiCorp and PPM Energy must submit a market analysis jointly. In February 2005, PacifiCorp and PPM Energy submitted their joint triennial market power analysis to the FERC. In May 2005, the FERC instituted a proceeding to determine whether PacifiCorp and PPM Energy may continue to charge market-based rates for sales of wholesale energy and capacity. PacifiCorp and PPM Energy are in the process of responding to the FERC s request that additional information and analysis be submitted within 60 days in an attempt to rebut the presumption that PacifiCorp and PPM Energy have generation market power.

12 Regulation of PacifiCorp

Multi-State Process (MSP)

PacifiCorp initiated a collaborative process with stakeholders in five of the six states it serves, aiming to develop and implement a cost allocation methodology that would achieve a more permanent consensus on each state s responsibility for the costs of, and entitlement to the benefits of, PacifiCorp s existing assets. This was intended to enable PacifiCorp to recover the full cost of future investments and provide states with the ability independently to implement state energy policy objectives. Between April 2002 and December 2003, extensive discussions between PacifiCorp and key parties within its service areas led to the development of a Protocol cost allocation methodology, which was filed in Utah, Oregon, Wyoming, Idaho and Washington. Following discussions with all parties, this proposal was refined and re-submitted to each of the state commissions as the Revised Protocol . Final ratification of the Revised Protocol occurred in March 2005 with each of the state commissions in Utah, Oregon, Wyoming and Idaho issuing orders approving and accepting the use of the Revised Protocol cost allocation methodology for future rate setting in each of those states. In accordance with this agreement, ongoing rate case filings in Oregon and Idaho have been based on the Revised Protocol and the recent Utah settlement was based on Revised Protocol. In Washington, the Washington Utilities and Transportation Commission (WUTC) issued its formal order approving and adopting the Washington general rate case settlement, accepting the Revised Protocol for reporting purposes and establishing a process for ongoing discussions for a permanent allocation methodology during 2005/06. The Revised Protocol will be filed in the state of California with the next general rate case.

Regional Transmission Arrangements

PacifiCorp, in conjunction with nine other utilities, has established a non-profit corporation, known as Grid West. If and when fully implemented, it would serve as an independent transmission provider for the Grid West region and have the operational authority needed to direct bulk wholesale electricity transfers over a majority of the 60,000 miles of transmission lines owned by its members. Grid West would have operational control but PacifiCorp would continue to own its transmission assets. Creation of Grid West is in response to the FERC s Order 2000 and is subject to regulatory approvals from the FERC and state regulatory commissions. In December 2004, the filing utilities, in collaboration with regional stakeholders, adopted new bylaws for Grid West s interim board, on which PacifiCorp has a representative. The parties are now engaged in the continuing development of the regional proposal together with work on inter-regional issues in conjunction with other regional transmission operators.

Relicensing of Hydroelectric Projects

PacifiCorp s hydroelectric portfolio consists of 51 plants with a plant net capability of 1,155 MW, about 15% of PacifiCorp s total generating capacity. The majority of the hydroelectric generating portfolio is operated under licences from the FERC, granted for periods of 30 to 50 years. There is a complex regulatory process to apply for licence renewal which begins five and a half years before the expiration of an existing licence and involves a number of federal and state agencies, Native American tribes and other stakeholders. Some state and federal agencies have mandatory authority to require certain terms and conditions to be included in the FERC licence. Often existing licences expire prior to the FERC s issuing of a new licence. In these cases, the FERC has historically issued annual operating licences so that the project can continue to operate while alternatives are evaluated; the FERC is continuing this practice.

In order to facilitate the licensing process, PacifiCorp may agree to early implementation of expected licence conditions, or settlement terms, if a settlement has been reached with licensing stakeholders. The cost of these measures, together with the costs for hydroelectric relicensing, are expected to be included in rates and, as such, not to have a material adverse impact on the group s consolidated results of operations. Relicensing and decommissioning of individual hydroelectric installations are an ongoing part of the PacifiCorp business and, in 2004/05, new licences were issued for the Bear River and Big Fork projects (some 89 MW) whilst settlements were agreed for the removal of the American Fork, Condit and Powerdale projects (some 17 MW).

Regulatory Established Returns

The regulatory commissions in the various states where PacifiCorp operates approve levels of cost recovery for debt,

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preferred equity and common equity which result in an allowed return on rate base costs, including an allowed return on equity (ROE) which represents the return on shareholder investment. Determination of these returns, and the composition of the investment costs included in the rate base, is made by the commissions through general rate cases. Rates are then set to allow PacifiCorp the opportunity, with no guarantees, to meet its expenses, recover its investments and earn the allowed ROE for its shareholders. PacifiCorp pursues a regulatory programme in all states, with the objective of keeping rates closely aligned to ongoing costs. In recently completed general rate cases, base rates in Utah increased by $65.0 million annually starting in April 2004, resulting in an average price increase of 7.0% and, in February 2005, the UPSC approved a stipulation settling PacifiCorp s general rate case filed in August 2004 under which base rates in Utah increased by $51.0 million annually starting in March 2005, resulting in an average price increase of 4.7% and an allowed return on equity of 10.5%. In September 2004, the Wyoming Public Service Commission (WPSC) approved a stipulation for a stand-alone pass-on of increased net wholesale purchased electricity costs. This stipulation was effective from 15 September 2004 and resulted in an overall price increase of $9.25 million annually, or 2.7%. In October 2004, the WUTC issued an order adopting a multi-party settlement agreement with limited conditions. A subsequent supplemental order was issued in November 2004, resulting in a total rate increase of $15.5 million annually, or 7.8%, effective from 16 November 2004.

PacifiCorp continues to refine its internal procedures and to work with the commissions to ensure that all prudently incurred costs are reflected in its rates. General rate adjustments reflecting changes in the regulated cost base granted during 2004/05 have an annualised value of approximately $ 75 million. Further rounds of rate cases are in progress, under consideration or in development in most of the states served by PacifiCorp. In this context, PacifiCorp has proposed or initiated discussion of power cost adjustment mechanisms designed to be longer-term, ongoing mechanisms that pass through to customers a portion of excess power costs, or return to customers a portion of over-collected power costs. These would enable power costs included within rates to be more closely aligned with PacifiCorp s actual costs and assist in reducing earnings volatility. As with any general rate case, the outcome of these discussions and requests is uncertain.

Future Generation, Renewable Energy and Conservation

As required by state regulators, PacifiCorp uses its IRP to provide a framework for prudent future actions required to help ensure that it continues to provide reliable and cost-effective electricity services to its customers. The IRP process identifies PacifiCorp s anticipated future resource mix in a coordinated dialogue with the stakeholders in each of the six states in which PacifiCorp operates. It allows PacifiCorp to continue to select optimal solutions from a mix of renewable, thermal, market purchase and demand side management choices, guiding specific build or buy decisions made dependent on permitting, siting, emissions, cost recovery and economic conditions. Dockets have been established in Utah, Oregon, Idaho and Washington to determine acknowledgment of the plan under which costs incurred by PacifiCorp to provide service to its customers are expected to be included as allowable costs for ratemaking purposes. However, under the US regulatory compact , PacifiCorp must demonstrate to regulators that its incurred costs are both reasonable and necessary to the provision of safe, adequate, reliable and efficient electricity utility services to its retail customers and that its decisions were made in a prudent manner.

As part of the 2004 IRP process, PacifiCorp has identified a potential future difference between retail load obligations and available resources which it plans to meet through a combination of investment in new generation and load control programmes. Major IRP action items are formed into a series of separate RFPs, each of which focuses on a specific category of requirement, including energy conservation programmes (450 average MW) and the 1,400 MW of economic renewable resources that were first identified in the 2003 IRP. Since the US Congress renewed the federal Production Tax Credit (PTC) for renewable energy in late 2004, PacifiCorp has concentrated its efforts on renewable energy generation that could come on-line by the end of 2005, when the PTC expires pending further extensions. Projects that can incorporate the PTC s value benefit by 1.8 cents per kWh over the first 10 years of a plant s operation. At 31 March 2005, PacifiCorp was negotiating with top bidders for 2005 projects, with plans subsequently to move on to 2006 projects.

To date, PacifiCorp has entered into a 64.5 MW power purchase agreement, to take effect prior to calendar 2006, for the output of a windfarm located in southeastern Idaho. PacifiCorp is continuing to negotiate with other counterparties to increase its use, storage and delivery of renewable energy beyond the approximately 1,000,000 MWh of 2004/05. Based on data compiled by the US Department of Energy, PacifiCorp ranks second nationwide in customer participation and third in MWh sales in voluntary renewable energy programmes. The benefits of renewable energy include low to no emissions and no fossil fuel requirements but wind and solar generation are intermittent, so complementary thermal or hydroelectric resources are important to integrate renewable resources into the electricity system.

In addition to the supply-side RFPs, in June 2003 PacifiCorp issued a separate RFP requesting an additional 100 MW or more of conservation to be obtained over the next 10 years and load control proposals specifically addressing peak load. Two conservation programmes and one load control programme were selected. Tariffs for each programme have been filed with the UPSC.

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Business Review Description of Legislative and Regulatory Background

Competition and Deregulation

During 2004/05, PacifiCorp continued to operate its electricity distribution and retail business under state regulation, which generally prohibits retail competition. However, as a result of Direct Access mandated by Oregon s Senate Bill 1149, a group of customers having a total average load of approximately 18 MW has chosen service from suppliers other than PacifiCorp. A group of customers having a total average load of approximately 2 MW has taken service from PacifiCorp at the Daily Market Pricing Option, which links the energy charge on a customer s bill to a representative market price index. These changes will not have a material effect on PacifiCorp s earnings. In addition to Oregon s Direct Access programme, others in PacifiCorp s service territories are seeking choice of suppliers, options to build their own generation or co-generation plants, or the use of substitute energy sources such as natural gas. If these other customers gain the right to receive electricity from alternative suppliers, they will make their energy purchasing decision based upon many factors, including price, service and system reliability. Availability and price of alternative energy sources and the general demand for electricity also influence competition. PacifiCorp does not expect significant retail competition in the near future.

A summary of the outcomes and the most significant further regulatory and legislative developments in the states concerned is set out below. The summary below does not include the possible effect of the proposed sale of ScottishPower s indirect interest in PacifiCorp to MidAmerican. In each state, the sale of PacifiCorp will require regulatory notification and/or approval. Although PacifiCorp intends to pursue general rate increase requests as currently planned, management is unable to predict the impact, if any, of the proposed sale and the process of obtaining such approvals, on the pending matters described below.

Utah

In August 2004, PacifiCorp filed a general rate case request with the UPSC related to operating cost increases and recovery of investments that support Utah s growing demand and need for enhanced network reliability. In October 2004, the UPSC approved the use of a forward-looking test year in this general rate case, the year 2005/06, and in February 2005 approved a stipulation settling the general rate case. Under the stipulation, base rates in Utah increased by $51.0 million annually starting in March 2005, resulting in an average price increase of 4.7% and an allowed return on equity of 10.5%.

Senate Bill 26 was signed into law in February 2005 and establishes rules and a mandatory process for the solicitation and evaluation of bids to procure significant energy resources. It also provides PacifiCorp with the

Oregon

In May 2004, the Oregon Court of Appeals heard oral arguments concerning appeals made against the Marion County, Oregon circuit court affirmation of a 2002 Oregon Public Utility Commission (OPUC) order which authorised PacifiCorp s recovery of $131.0 million of excess net power costs, plus carrying charges, at a rate of $45.6 million annually. In October 2004, the Oregon Court of Appeals affirmed the circuit court decision. The deadline for further appeals has now passed. At 31 March 2005, approximately $13.7 million remained to be collected by the authorised surcharge.

In November 2004, PacifiCorp filed a general rate case with the OPUC related to increases in operating costs, including fuel, purchased power, and pension and healthcare costs. PacifiCorp is seeking an increase of $102.0 million annually, or 12.5%. Any increase would take effect in September 2005. Settlement conferences were held in April 2005 and hearings are scheduled for July 2005. PacifiCorp has also made filings designed to provide for discussion regarding the development of a power cost adjustment mechanism.

Wyoming

In April 2004, PacifiCorp filed a complaint with the federal district court in Wyoming challenging the March 2003 decision of the WPSC to deny recovery of Hunter No. 1 replacement power costs and deferred excess net power costs on the grounds that the decision violates federal law by denying PacifiCorp recovery in retail rates of its wholesale electricity and transmission costs incurred to serve Wyoming customers. The lawsuit seeks an injunction requiring the WPSC to pass through PacifiCorp s wholesale electricity and transmission costs in retail rates. In May 2004, the WPSC filed a motion to dismiss the complaint; the motion to dismiss was denied in November 2004. In January 2005, the WPSC appealed the court s ruling on the motions to dismiss and requested a stay of the underlying litigation. In February 2005, the Tenth Circuit Court of Appeals denied the WPSC interlocutory appeal of the court s ruling; this decision is subject to a currently active appeal.

In October 2004, the WPSC approved a stipulation filed by PacifiCorp, Powder River Energy Corporation and Kennecott Energy Company to resolve an attempt by Powder River Energy Corporation and Kennecott Energy Company to allow Kennecott Energy Company to choose its electricity service provider for the Antelope Coal Mine, which is in PacifiCorp s service territory and has been served by PacifiCorp for 20 years. The terms of the stipulation include a continued recognition of PacifiCorp s authorised territory through a regulatory recovery fee payment that Kennecott Energy Company will make to PacifiCorp. The regulatory recovery fee protects other Wyoming customers from any impacts due to the loss of the mine opportunity to obtain advance approval from the UPSC of a resource decision and an assurance of the recovery of costs associated with the resource.

load. Powder River Energy Corporation will be the sole energy provider to the mine.

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In July 2004, PacifiCorp applied to the WPSC for a standalone pass-on of increased net wholesale purchased electricity costs. Following discussions with various parties, PacifiCorp filed a joint stipulation valuing this request at $9.25 million annually, or 2.7%. This stipulation was heard by the WPSC and approved effective 15 September 2004. The expedited treatment of this application was recognised in the stipulation with an agreement that PacifiCorp will not file a general rate application until at least September 2005. Further, the parties agreed to hold discussions on the development of a commodity cost recovery mechanism and alternative forms of regulation.

Washington

In December 2003, PacifiCorp filed with the WUTC for a general rate increase and requested that the WUTC adopt the findings of a prudence review of generating resources acquired since the last Washington general rate case. In October 2004, the WUTC issued an order adopting the multi-party settlement agreement with limited conditions and, in November 2004, the WUTC issued a supplemental order with revised calculations. As a result, the WUTC authorised an annual increase of $15.5 million, or 7.8%, effective 16 November 2004. On 5 May 2005, PacifiCorp filed a general rate case request for approximately $39 million related to increased operating costs and investment in new generation. The rate case also seeks the use of a forward-looking test year, implementation of a power cost adjustment mechanism and ratification of the MSP Revised Protocol.

Idaho

In December 2003, PacifiCorp filed with the Idaho Public Utilities Commission (the IPUC) to recover Idaho s portion of income tax payments resulting from Internal Revenue Service audits of prior years. In April 2004, the IPUC staff held public input meetings concerning PacifiCorp s application. A stipulated agreement signed by the parties was filed with the IPUC in May 2004 and was approved by the IPUC in June 2004. This allowed recovery of $4.2 million over 16 months beginning in June 2004 when a power cost recovery surcharge, which began in June 2002, expired.

In January 2005, PacifiCorp filed a general rate case with the IPUC related to continuing investment to serve Idaho load, increases in employee-related costs and general inflation impacts. PacifiCorp seeks an increase of $15.1 million annually, or 12.5%. If approved by the IPUC, new rates would take effect 16 September 2005. On that date, unrelated surcharges currently in effect will expire, so the net effect to customers of this increase would be $11.4 million annually, or 9.2%, overall.

13 Regulation of the Electricity and Gas Industries in the UK

The UK electricity and gas industries are regulated under the provisions of the Electricity Act, the Gas Acts, the Utilities Act and the Energy Act 2004. The Electricity and Gas Acts provided for the privatisation and restructuring of the industries in the late 1980s and the 1990s, including the introduction of price regulation for electricity transmission and distribution and gas transportation; and of competition in electricity generation, gas storage and the supply of both gas and electricity. The Electricity and Gas Acts established the licensing of industry participants and created regulatory bodies for each of the electricity and gas industries. In 2000, the Utilities Act enabled the electricity and gas regulators to be merged as the Authority, established new independent consumer councils and provided powers for Government Ministers to give statutory guidance on social and environmental issues and to set energy efficiency targets and renewables obligations. In 2004, the Energy Act provided the Secretary of State for Trade and Industry (Secretary of State) with powers to implement Great Britain-wide electricity trading and transmission arrangements.

The Utilities Act transferred the functions of the previous electricity and gas industry regulators to the Authority and provided for the appointment of a Chairman and other members of the Authority by the Secretary of State. The Chairman of the Authority holds office for renewable periods of five years, and its Chief Executive is also the Chief Executive of Ofgem which provides administrative support to the Authority. Under the Utilities Act, the principal objective of the Secretary of State and the Authority is to protect the interest of customers, wherever appropriate by promoting effective competition. In carrying out those functions, they are required to have regard to the need to secure that all reasonable demands for electricity and gas are met; the need to ensure that licence holders are able to finance their functions; and the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes or residing in rural areas. The Authority exercises, concurrently with the Director General of Fair Trading, certain functions relating to monopoly situations under the Fair Trading Act 1973 and the Enterprise Act 2002 and to anti-competitive conduct under the Competition Act 1980 and the Competition Act 1998. The Authority also manages UK compliance with the European Community Liberalisation Directive, which is concerned to introduce competition in generation and supply and non-discriminatory access to gas transportation and electricity transmission and distribution across the EU.

The Licensing Regime

The Authority is responsible for granting new licences or licence extensions for each of the following separate activities:

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Business Review Description of Legislative and Regulatory Background

Electricity Generation   the production of electricity at power stations, hydroelectric plants, windfarms and some industrial plants. Through its wholly-owned subsidiary, ScottishPower Generation Limited, the group is licensed to operate some 6,200 MW of generating capacity and, by contracting in the wholesale market, has access to capacity operated by other licensed generators.

Electricity Transmission   the bulk transfer of electricity across a high-voltage network of overhead lines, underground cables and associated equipment typically operating at or above 132 kV. Through its wholly-owned subsidiary, SP Transmission Limited, the group owns the transmission system in central and southern Scotland. ScottishPower s transmission system is connected to that of Scottish and Southern Energy in the north of Scotland and is linked to the National Grid in England & Wales. It is also linked to the Northern Ireland transmission system by interconnectors that enable the export and import of electricity between the two systems. From 1 April 2005, under BETTA, operation, but not ownership, of the group s transmission system was passed to the Great Britain-wide transmission system operator, National Grid Transco plc.

Electricity Distribution   the transfer of electricity from the high voltage transmission system and its delivery to customers, across a network of overhead lines and underground cables operating at voltages ranging from 33 kV (132 kV in England & Wales) to 0.23 kV. The Utilities Act required separate licensing of the 14 regional distribution businesses introduced under electricity privatisation. Each Public Electricity Distributor licensee is required, among other duties, to develop and maintain an efficient, coordinated and economical system of electricity distribution and to offer terms for connection to, and use of, its distribution system on a non-discriminatory basis, in order to ensure competition in the supply and generation of electricity. Through its wholly-owned subsidiaries, SP Distribution Limited and SP Manweb plc, the group is licensed to distribute electricity within its two distribution services areas for all suppliers whose customers are within the areas. Charges for distribution are made to the various suppliers as appropriate.

Gas Transportation and Storage   the onshore transportation system, most of which is owned and operated by Transco, the transportation arm of National Grid Transco plc, and the rest by other gas transporters, conveys gas from the beach terminals to consumers and is interconnected with the gas transportation systems of continental Europe, Northern Ireland and the Republic of Ireland. Storage capacities are largely used to balance supply and demand over time. Major facilities are used to balance seasonal variations in demand while diurnal storage capacities provide flexibility in meeting changing gas demand on a daily basis. Competition in storage has been introduced progressively since 1998 through the auction of major storage capacity owned by Transco and the provision of new capacity by independent operators, including ScottishPower.

Gas Shipping   gas shippers contract with gas transporters to have gas transported between the beach terminal and the point of supply. Gas shippers can also access storage facilities. The group is licensed as a gas shipper.

Supply of Gas and Electricity   the bulk purchase of gas and electricity by suppliers and its sale to customers, with the associated customer service activities, including customer registration, meter reading, sales and marketing, billing and revenue collection. Large industrial and commercial customers have been able to choose their energy suppliers for a number of years and the residential market was opened to competition progressively, commencing in April 1996, with residual controls on residential electricity prices ending in March 2002. Any electricity supplier wishing to supply electricity to domestic customers must obtain authorisation from the Authority and be subject to additional domestic supply obligations in its licence, including having its codes of practice (statements of intent about how the supplier will interact with customers) approved by the Authority. Broadly comparable arrangements allow British Gas Trading to supply mains gas to any connected customer in competition with licensed gas suppliers. Customers may continue to take supplies from the pre-privatisation monopoly supplier for the area or may choose an alternative licensed supplier. Once customers have changed a gas or electricity supplier, they are able to change supplier again subject to the contractual terms offered by licensed suppliers and approved by the Authority. Through its wholly owned subsidiary, ScottishPower Energy Retail Limited, the group is licensed as a gas supplier and an electricity supplier.

Modification of Licences

The Authority is responsible for monitoring compliance with the conditions of licences and, where necessary, enforcing them through procedures laid down in the Electricity and Gas Acts. Under these Acts, as amended by the Utilities Act, licences consist of standard licence conditions, which apply to all classes of licences, and special conditions particular to that licence. The Authority may modify standard licence conditions collectively through making proposals to all relevant licence holders. If some licence holders object, the modification may be carried out only if the number of objectors is below a specified minority. The Authority may modify a special licence condition with the agreement of the licence holder after due notice, public consultation and consideration of any representations or objections. In the absence of agreement for a special licence condition or if objections are above the specified minority threshold for a standard licence condition, the only means by which the Authority can secure a

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modification is following a modification reference to the Competition Commission and in the circumstances set out below. A modification reference requires the Competition Commission to investigate (having regard to the matters in relation to which duties are imposed on the Secretary of State and the Authority) and report on whether matters specified in the reference in pursuance of a licence operate, or may be expected to operate, against the public interest; and, if so, whether the adverse public interest effect of these factors could be remedied or prevented by modification of the conditions of the licence. If the Competition Commission so concludes, the Authority must then make such modifications to the licence as appear to it requisite for the purpose of remedying or preventing the adverse effects specified in the report, after giving due notice and consideration to any representations and objections. The Secretary of State has the power to veto any modification.

Modifications to licence conditions may also be made in consequence of a reference under the Fair Trading Act 1973, the Enterprise Act 2002 or the Competition Act. ScottishPower s acquisition of Manweb in 1995 and its merger with PacifiCorp in 1999 both involved ScottishPower s giving of undertakings to the Secretary of State to agree to modifications to the licences under which the group operates in the UK. Broadly, these modifications were designed to ring-fence various UK regulated businesses, to require that the group had sufficient management and financial resources to fulfil its UK obligations and to ensure that UK regulators would continue to have access to the information needed to carry out their duties.

Term and Revocation of Licences

Licences under the Electricity Act, as modified by the Utilities Act, may be terminated by not less than 25 years notice given by the Secretary of State and may be revoked in certain circumstances specified in the licence. These include the insolvency of the licensee, the licensee s failure to comply with an enforcement order made by the Authority and the licensee s failure to carry on the activities authorised by the licence.

Price Controls

It is recognised that the development of competitive markets is not appropriate in some areas: particularly in the core activities of transmission and distribution of electricity and the operation of the gas transportation system. In these areas, regulatory controls are deemed necessary to protect customers in monopoly markets (by determining inflation-limited price caps) and to encourage efficiency. The group s UK transmission and distribution businesses are subject to price controls (or revenue controls in the case of the transmission business) which restrict the average amount, or total amount, charged for a bundle of services. The price caps are expressed in terms of an RPI X constraint on charges, where RPI represents the annual percentage change in the UK s retail price index, and X is a percentage determined by the Authority. The X factor is used to reflect expected efficiency gains and investment requirements. For example, where RPI is running at 3% and X is 2%, a company would be able to increase the average charge for a bundle of services by 1% per annum. The Authority from time to time reviews the price cap formulae. Through participation in, and the submission of evidence to, these price control reviews and, where necessary, through the Competition Commission modification process described above, companies have the opportunity to comment on and seek to influence the final outcome of any price control review.

Transmission Price Control

The revised transmission price control for ScottishPower took effect for the five years from 1 April 2000 and, under the terms of BETTA, which establishes a Great Britain-wide wholesale market for electricity, the price control for SP Transmission has been extended for two years from 1 April 2005.

Distribution Price Control

The maximum distribution revenue is calculated from a formula that is based on customer numbers as well as units distributed. Distribution price controls for the SP Distribution and SP Manweb operating areas, which took effect for the five years from 1 April 2005, provide incentives for distribution companies to enhance returns through performance improvements and to connect distributed generation and renewables.

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14 Environmental Regulation

Throughout its operations, ScottishPower strives to meet, or exceed, relevant legislative and regulatory environmental requirements and codes of practice. ScottishPower will publish its 2004/05 Environmental and Social Impact Report and Environmental Performance Report in October 2005. Copies will be available on request from the Company Secretary and the reports will be available on the ScottishPower website.

US Environmental Regulation

US federal, state and local authorities regulate many PacifiCorp and PPM Energy activities pursuant to laws and regulations designed to prevent and control pollution and restore, protect and enhance the quality of the environment. These laws and regulations govern the construction, permitting, operation and closure of PacifiCorp and PPM Energy facilities. In general, these laws and regulations have increased the cost of providing electricity service and give rise to permit and pollution control requirements and other liabilities, principally in respect of Clean Air Act matters, which are often the subject of

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Business Review Description of Legislative and Regulatory Background

discussions and negotiations with the US Environmental Protection Agency (EPA) and state regulatory authorities. In addition, US environmental laws and regulations have become more stringent over time, and future changes in US environmental laws or regulations could increase PacifiCorp s operating costs, including those relating to site clean-up and closure, and give rise to challenges in obtaining and maintaining required operational permits. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of capital expenditures required to upgrade or modify facilities to control or reduce regulated emissions. PacifiCorp expects to manage its decision making and implementation of these matters effectively so that these and future costs will be found to be prudent and recoverable in rates and, as such, will not have a material adverse impact on the group s consolidated results of operations.

Air Quality

PacifiCorp and PPM Energy s fossil fuel-fired electricity generation plants, as well as other facilities with significant air emissions, are subject to regulation under federal, state and local air pollution permitting and pollution control and reduction requirements, primarily those under the federal Clean Air Act and associated regulations. PacifiCorp and PPM Energy believe they have all required permits and other approvals to operate their plants and that the plants are in material compliance with applicable requirements. PacifiCorp uses emission controls, low-sulphur coal, plant operating practices sensitive to possible environmental impacts and continuous emissions monitoring to ensure that its plants comply with visible emissions, opacity and criteria pollutant limits and other air quality requirements. Federal and state air quality laws and regulations have and will become more stringent over time. In particular, the EPA has initiated a regional haze programme intended to improve visibility at specific federally protected areas, some of which are located near PacifiCorp plants. This programme could require affected PacifiCorp facilities to further reduce visible emissions through capital expenditures for pollution controls or operational changes. PacifiCorp is working with the Western Regional Air Partnership to help develop the technical and policy tools needed to comply with those regulations.

Carbon dioxide (CO_2) emissions are the subject of growing discussion and action in the context of global climate change, but such emissions are not currently subject to regulation. PacifiCorp is anticipating climate change challenges with additions of renewable generation, conservation and thermal resources as outlined in the IRP. CO_2 emissions risk has been recognised in PacifiCorp s IRP through the use of a projected additional cost applied to CO_2 emissions when evaluating the cost of proposed resources. PacifiCorp also supports development of US or global trading and other market mechanisms, as well as offset strategies, where feasible, to reduce future compliance costs to customers.

The US Congress is currently considering several proposed bills that would modify the overall enforceable limits on electricity plant emission of sulphur dioxide (SO_2), oxides of nitrogen (NOx), mercury and in some cases CO_2. These proposed laws and regulations advocate a cap and trade approach to overall reduction of air emissions from power facilities, which would allow generation facilities to meet more stringent emissions limits through the purchase of emission credits and/or additional pollution controls. The EPA also has finalised new regulations that could impact emissions and is pursuing enforcement actions against selected coal-fired power plants in the eastern and mid-western US with the aim of causing nationwide emission reductions. All of these efforts may lead to additional control equipment being installed over the next 10-15 years. PacifiCorp expects that future costs relating to these matters may be significant and would consist primarily of capital expenditure but will be spread over a number of years. PacifiCorp also expects that these costs will be recovered through regulatory ratemaking.

Endangered Species

Protection of threatened and endangered species and their habitat makes it difficult and more costly to perform some of the core activities of the US businesses, including the siting, construction, maintenance and operation of new and existing transmission and distribution facilities, as well as hydroelectric, thermal and wind generation plants. In addition, endangered species issues impact the relicensing of existing hydroelectric generating projects, generally raising the price PacifiCorp pays to purchase wholesale electricity from hydroelectric facilities owned by others as well as reducing the generating output and operational flexibility and increasing the costs of operation of PacifiCorp s own hydroelectric resources. PacifiCorp creates and implements management systems to ensure that environmental considerations are successfully incorporated into major business decisions relating to its generation, transmission and distribution assets.

Environmental Clean-ups

Under the federal Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act and similar state statutes, entities that accidentally or intentionally dispose of, or arrange for the disposal of, hazardous substances may be liable without regard to fault for the clean-up of the contaminated property. In addition, the current or former owners or operators of contaminated sites also may be strictly liable for corrective action costs. PacifiCorp has been identified as a potentially responsible party for the costs for site clean-up in connection with a number of current or formerly owned sites or third party sites where PacifiCorp is alleged to have arranged for the disposal of hazardous substances from its operations.

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PacifiCorp has completed several clean-up actions and is actively participating in investigations and remedial actions at other sites.

Mining

The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish permitting, siting, operational, reclamation and closure standards that must be met during the operation and upon completion of mining activities. These obligations mandate that mine property be restored consistent with specific standards and the approved reclamation plan. Significant expenditures are expected to be required as individual PacifiCorp mining operations are closed and reclamation occurs.

Water Quality

The federal Clean Water Act and individual state clean water regulations require permits for the discharge of wastewater, including storm water runoff from the electricity plants and coal storage areas, into surface waters and groundwater. PacifiCorp and PPM Energy believe they have management systems in place to monitor performance, identify problems and take action to assure compliance with wastewater permit and other Clean Water Act requirements. Additionally, PacifiCorp believes it currently has, or has initiated the process to receive, all required water quality permits.

UK Environmental Regulation

The group s UK businesses are subject to numerous regulatory requirements with respect to the protection of the environment, including environmental laws which regulate the construction, operation and decommissioning of power stations, pursuant to legislation implementing environmental directives adopted by the EU and protocols agreed under the auspices of international bodies such as the United Nations Economic Commission for Europe (UNECE). The group believes that it has taken and continues to take measures to comply with applicable laws and regulations for the protection of the environment. Applicable regulations and requirements pertaining to the environment change frequently, however, with the result that continued compliance may require material investments, or that the group s costs and results of operation are less favourable than anticipated.

Electricity Generation, Transmission, Distribution and Supply

Assessment Regulations, to carry out an environmental assessment when it intends to construct significant overhead transmission systems or power stations of greater capacity than 50 MW. The group also prepares formal statements on the Preservation of Amenity and Fisheries in line with the requirements of the Electricity Act.

The Utilities Act provided for environmental guidance to be given by the Secretary of State to the energy regulator, Ofgem, and for regulations to be drawn up which require licensed electricity suppliers to secure a certain percentage of their supplies from renewable energy sources, compliance being demonstrated by tradable Renewables Obligation Certificates (ROCs) or payment of a Buyout Fine . The current legislative requirement is that 15.4% of UK energy should come from renewable sources by 2015. ScottishPower continues to develop its windfarm and renewables business in support of these requirements. In April 2005, the UK Government also introduced amending legislation to recognise ROCs generated in Northern Ireland, creating a single UK-wide market for trading ROCs from April 2005.

The Utilities Act also provided for residential energy efficiency targets to be set for licensed suppliers and to be implemented by an Energy Efficiency Commitment (EEC). The savings target, set by Ofgem, is to achieve fuel-weighted energy benefits, which will make a contribution to carbon savings in the UK Government s Climate Change Programme. ScottishPower has met its targets for EEC1 (operating between April 2002 and March 2005) with the delivery of over 4.5 Terawatt hours of energy saving benefits. The revised scheme, called EEC2, will run from April 2005 to March 2011 with a formal review to take place in 2008.

The Environmental Protection Act of 1990 (EPA 1990) requires that potentially polluting activities such as the operation of combustion processes (which includes power plant) requires prior authorisation. The Act also provides for the licensing of waste management and imposes certain obligations and duties on companies which produce, handle, and dispose of waste. Waste generated as a result of the group s electricity activities is managed to ensure compliance with legislation and waste minimisation is undertaken where possible.

Generation Activities

The principal emissions from fossil-fuelled electricity generation are SO_2, NO_x, CO_2 and particulate matter, such as dust, with the main waste being ash, namely pulverised fuel ash and furnace bottom ash. The primary focus of previous environmental legislation has been to reduce emissions of SO_2, NOx and particulates, the first two of which contribute to acid rain. A number of other power station emissions and discharges are subject to environmental regulation.

The EU Emissions Trading Scheme is one of the policies being introduced across Europe to help implement the Kyoto

The Electricity Act obligates the Secretary of State to take into account the effect of electricity generation, transmission, distribution and supply activities upon the physical environment in approving applications for the construction of generating facilities and the location of overhead power lines. The Electricity Act requires the group to take into account the conservation of natural features of beauty and other items of particular interest and, in terms of the Environmental Impact

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Business Review Description of Legislative and Regulatory Background

Protocol to tackle emissions of carbon dioxide and other greenhouse gases and to combat the threat of climate change. The scheme commenced on 1 January 2005 and works on a cap and trade basis where installations are allocated a number of allowances which they can then trade to achieve reduced CO_2 emissions at least cost. The number of allowances allocated to each installation is set down in a document called the National Allocation Plan (NAP) which Member States were required to submit to the European Commission (EC) in 2004. The UK s final NAP was published on 24 May 2005 and outlined the number of free allocations to be issued to each installation in the UK during 2005 to 2007. ScottishPower has 13 installations covered by the scheme and under the final NAP received just under 14 million tonnes of free CO_2 per annum. ScottishPower has fully integrated CO_2 management into its energy portfolio and manages CO_2 as a commodity alongside power, gas and coal.

EPA 1990 is the primary UK statute governing the environmental regulation of power stations. In April 1991, it introduced a system of Integrated Pollution Control (IPC) for large scale industrial processes, including power stations, now enforced with respect to emissions to atmosphere in England & Wales by the Environment Agency (EA) and in Scotland by the Scottish Environment Protection Agency (SEPA). Each of ScottishPower s power stations is required to have its own IPC authorisation, issued by the EA or SEPA, regulating emissions of certain pollutants, seeking to minimise pollution of the environment and containing an improvement programme. Each IPC authorisation requires that a power station uses the Best Available Techniques Not Entailing Excessive Cost (BATNEEC) to prevent the emissions described above or, to the extent this is not practicable, to minimise and render harmless any such emissions. ScottishPower s IPC authorisations do not have an expiry date, but the EA or SEPA is required to review the conditions contained within them at least once every four years and may impose new conditions to prevent or reduce emissions of pollutants, subject to the application of BATNEEC.

The EU has agreed a Directive on Integrated Pollution Prevention and Control, which introduces a system of licensing for industrial processes such as power stations. This Directive is being implemented via the Pollution Prevention and Control (PPC) Regulations which will bring modifications to the IPC regime into effect, on a staged basis. The EU Directive will eventually require that all emission and pollution control measures are placed onto a Best Available Techniques (BAT) basis to control the impact on the environment. Existing large combustion plants, including power stations, are due to transfer over to the PPC regime during 2006 and must apply for PPC Permits during the period January to March 2006. ScottishPower has six such plants. New plant must immediately comply with the PPC requirements and BAT.

The EU has adopted a framework directive on ambient air quality assessment and management and, under the auspices of UNECE, protocols regarding reductions in the emissions of SO_2 and NOx have been agreed. These protocols are currently implemented in the EU by means of the Large Combustion Plants Directive (LCPD) and the revision of this Directive will implement tighter controls on emissions to air from 2008. The EU has finalised a Ceilings Directive which will implement the SO_2 and NOx targets agreed in the UNECE Gothenburg Protocol. In the UK, the Government has submitted details to the EC of how it proposes to implement the LCPD. Continued uncertainty remains on final arrangements surrounding implementation of bulk emissions and emission limit values. Compliance with local air quality issues will continue to be implemented in the UK by means of the National Air Quality Strategy (NAQS) published in 1997, and reviewed in 2000. The provisions of the revised LCPD and of NAQS are to be introduced through the PPC permitting process on a plant-by-plant basis.

The group has identified options that, given the appropriate commercial conditions, would enable it to continue the environmental improvements required by potential future limits arising from this review, without materially constraining operational and commercial flexibility.

Contaminated Sites

While the nature of developments in environmental regulation and control cannot be predicted, the group anticipates that the direction of future changes will be towards tightening controls. In view of the age and history of many sites owned by the group, the group may incur liability in respect of sites which are found to be contaminated, together with increased costs of managing or cleaning up such sites. Site values could be affected and potential liability and clean-up costs may make disposal of potentially contaminated sites more difficult. The Contaminated Land Regulations, which implement provisions of the Environment Act 1995 (EA 1995), require local authorities to identify sites where significant harm is being caused and to take appropriate steps. In order for harm to be demonstrated it must be shown that a source of pollution, a receptor and a pathway are present. Harm may be eliminated by clean-up or by breaking the source to receptor pathway. Clean-up is only required to fit for subsequent use standards, so that environmental compliance is consistent with the intended use of the site.

Other proposals which may, under certain conditions impose strict liability for environmental damage, such as the Environmental Liability Directive, are presently being adopted by the EC. ScottishPower is not currently aware of any liability which it may have under EA 1995 or proposed

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EU directives which will have a materially adverse impact on its operations.

15 Employment Regulation

Each of the UK and the US has extensive legislation covering both health and safety and equal opportunities at work. ScottishPower has well-defined policies in place throughout its businesses to ensure compliance with applicable laws and related codes of practice. These policies cover a wide range of employment issues such as disciplinary action, grievance, harassment, discrimination, stress and whistle-blowing .

A more extensive description of how the businesses discharge their wider responsibilities to protect the welfare, health and safety of the public and their employees, can be found in the ScottishPower Environmental and Social Impact Report and the Workplace Performance Report, available on the ScottishPower website. A brief overview of the more extensively regulated aspects of employment follows.

Equal Opportunities

ScottishPower is committed to promoting equal opportunities for all, irrespective of age, colour, disability, ethnic or national origin, marital status, nationality, race, religion or similar belief, creed, sex, sexual orientation or any other considerations that do not affect a person s ability to perform their job. The company aims to promote equality of opportunity through the implementation of non-discriminatory policies, practices and initiatives in all aspects of employment in ScottishPower, including recruitment and selection, terms and conditions of employment, career development and retention.

The company aims to take particular action in respect of disability in order to encourage job applications from disabled candidates and to establish working conditions which encourage the full participation of people with disabilities. The company is committed to making all reasonable adjustments and accommodations necessary to attract, develop and retain people with disabilities. This includes the rehabilitation, training and reassignment of employees who develop a disability

ScottishPower works proactively with a range of organisations that promote equality of opportunity including in the UK, the Equal Opportunities Commission, Employers Forum on Age, Employers Forum on Disability, Job Centre Plus and The Council of British Pakistanis (Scotland). The Company also maintains positive relations with the federal and state compliance and enforcement agencies in the US, including the Department of Labor, the Office of Federal Contract Compliance Programs and the Equal Employment Opportunity Commission. ScottishPower HR in the UK and the US work with these organisations to find ways to incorporate their expertise into company policies.

Recent Developments

The UK Employment Act 2002 (Dispute Resolution) Regulations 2004, effective from October 2004, place a legal obligation on employers to follow certain minimum procedures when resolving workplace disputes. In order to comply with the Regulations, the company undertook a review of its existing employment procedures and concluded that the ScottishPower UK procedures far exceeded the minimum standards required.

The company has also undertaken a review of its existing UK consultation arrangements in order to comply with the Information and Consultation of Employees Regulations which come into force in April 2005. These Regulations give employees in larger firms rights to be informed and consulted on a regular basis about issues in the business they work for. Plans are in place to ensure that, by September 2005, each ScottishPower business in the UK has conducted a review of how it engages with its employees and produced an action plan which takes account of the Regulations. A further review of the company-level machinery will then be undertaken to support and maximise the aims of each business and of the ScottishPower employee relations philosophy.

In September 2004, California passed legislation requiring employers with 50 or more employees in California to provide sexual harassment training to all supervisory employees. The group s US businesses are developing and will implement sexual harassment training tailored to meet this requirement and will adapt relevant procedures to ensure tracking of all California supervisory employees in accordance with the law.

From 10 March 2005, US employers were required to post a notice informing employees of their rights under the Uniform Services Employment and Reemployment Act. Compliance with this federal law was ensured by sending e-mail notification of the law and the required posting of materials to the appropriate individuals.

Health and Safety

During January and February 2005, the performance of eight group businesses was assessed against the Group Health & Safety Standards. The results showed that 29% of the assessed business units achieved the level four or five expected of a world-class performer in comparison with 19% in 2003/04. A further 63% of the assessed business units met the level three threshold of demonstrable attention to the key issues compared with 54% in 2003/04.

US Businesses The lost time accident (LTA) rate for the US businesses increased from 0.66 to 0.92, an increase in LTAs from 42 to 59 during 2004/05 primarily due to an increase in the number of accidents in the power delivery business compared to the previous year. The highlight was PPM Energy

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maintaining its 0.0 LTA rate from prior years, whilst Pacific Klamath Energy was re-certified in the Oregon Sharp Program from the Oregon Occupational Safety and Health Administration.

The group s US Health & Safety Committee continues to meet on a regular basis, providing senior executive oversight and leadership in PacifiCorp and PPM Energy in these areas. Major initiatives are underway in PacifiCorp s power delivery, generation and mining business units and in PPM Energy to reduce and prevent accidents.

The US businesses participate with other industry stakeholders in the regulatory process on significant safety and health regulatory proposals affecting the utility and mining industries. PacifiCorp is also well represented amongst these stakeholders, with safety professionals occupying leadership positions in both mining and electricity trade associations safety groups.

UK Businesses The LTA rate for the UK businesses reduced from 0.62 to 0.42, a reduction in LTAs from 48 to 36. The highlight of the year was in the generation business which had a period of seven months without any LTAs and only two LTAs during the 12 months to April 2005.

In the UK, the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations set out the requirements for reporting of all work-related accidents. As UK regulators and enforcement authorities increasingly seek to raise the priority and importance that companies give to health and safety issues, they are likely to take action for any non-compliance. The company continues to support industry organisations, such as the Association of Electricity Producers and Energy Networks Association, and engages in representation to the UK Health and Safety Executive, the DTI and other relevant organisations through these industry groups.

16 Litigation

In May 2004, PacifiCorp was served with a complaint filed in the US District Court for the District of Oregon by the Klamath Tribes of Oregon and certain of the Klamath Tribes members. The claim generally alleges that PacifiCorp and its predecessors affected the Klamath Tribes federal treaty rights to fish for salmon in the headwaters of the Klamath River in southern Oregon by building dams that blocked the passage of salmon upstream to the headwaters beginning in 1911. The complaint seeks in excess of $1.0 billion in damages. PacifiCorp s motion for summary judgement and dismissal of the case was supported by the magistrate judge s recommendation in April 2005 but the Klamath Tribes objections to that recommendation, and PacifiCorp s response, are now before the court. Any final order will be subject to appeal.

The group s businesses are parties to various other legal claims, actions and complaints, certain of which may involve material amounts. Although the group is unable to predict with certainty whether or not it will ultimately be successful in these legal proceedings or, if not, what the impact might be, the directors currently believe that disposition of these matters will not have a materially adverse effect on the group s consolidated Accounts.

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17 Summary of Key Operating Statistics

Table 1

Ø **Summary of PacifiCorp Generating Facilities as at 31 March 2005**

	Location	Energy Source	Installation Dates	Plant Net Capability (MW)
Hydroelectric plants				
Swift	Cougar, Washington	Lewis River	1958	264.0
Merwin	Ariel, Washington	Lewis River	1931-1958	144.0
Yale	Amboy, Washington	Lewis River	1953	165.0
Five North Umpqua Plants	Toketee Falls, Oregon	N. Umpqua River	1950-1956	138.5
John C. Boyle	Keno, Oregon	Klamath River	1958	90.0
Copco 1 and 2	Hornbrook, California	Klamath River	1918-1925	54.5
Clearwater 1 and 2	Toketee Falls, Oregon	Clearwater River	1953	41.0
Grace	Grace, Idaho	Bear River	1908-1923	33.0
Prospect 2	Prospect, Oregon	Rogue River	1928	36.0
Cutler	Collingston, Utah	Bear River	1927	29.1
Oneida	Preston, Idaho	Bear River	1915-1920	28.0
Iron Gate	Hornbrook, California	Klamath River	1962	20.0
Soda	Soda Springs, Idaho	Bear River	1924	14.0
Fish Creek	Toketee Falls, Oregon	Fish Creek	1952	12.0
31 minor hydroelectric plants	Various	Various	1895-1990	86.3*
Subtotal (51hydroelectric plants)				**1,155.4**
Thermal electric plants				
Jim Bridger	Rock Springs, Wyoming	Coal-Fired	1974-1979	1,413.4*
Huntington	Huntington, Utah	Coal-Fired	1974-1977	895.0
Dave Johnston	Glenrock, Wyoming	Coal-Fired	1959-1972	762.0
Naughton	Kemmerer, Wyoming	Coal-Fired	1963-1971	700.0
Hunter 1 and 2	Castle Dale, Utah	Coal-Fired	1978-1980	662.0*
Hunter 3	Castle Dale, Utah	Coal-Fired	1983	460.0
Cholla Unit 4	Joseph City, Arizona	Coal-Fired	1981	380.0*
Wyodak	Gillette, Wyoming	Coal-Fired	1978	268.0*
Carbon	Castle Gate, Utah	Coal-Fired	1954-1957	172.0
Craig 1 and 2	Craig, Colorado	Coal-Fired	1979-1980	165.0*
Colstrip 3 and 4	Colstrip, Montana	Coal-Fired	1984-1986	149.0*
Hayden 1 and 2	Hayden, Colorado	Coal-Fired	1965-1976	78.0*
Blundell	Milford, Utah	Geothermal	1984	23.0
Gadsby	Salt Lake City, Utah	Gas-Fired	1951-2002	355.0
Little Mountain	Ogden, Utah	Gas-Fired	1972	14.0
Hermiston	Hermiston, Oregon	Gas-Fired	1996	245.0*
Camas Co-Gen	Camas, Washington	Black Liquor	1996	52.0
Subtotal (16 thermal electric plants)				**6,793.4**
Other plants				
Foote Creek	Arlington, Wyoming	Wind Turbines	1998	32.6*
Subtotal (1 other plant)				**32.6**
Total generating facilities				**7,981.4**

* Jointly owned plants; amount shown represents PacifiCorp s share only.

Note: Hydroelectric project locations are stated by locality and river watershed.

Table 2

Ø PacifiCorp Recoverable Coal Reserves as at 31 March 2005

Location	Notes	Plant Served	Recoverable Tons (in millions)
Craig, Colorado	1	Craig	48.4
Emery County, Utah	2	Huntington and Hunter	67.6
Rock Springs, Wyoming	3	Jim Bridger	143.1

Notes:

1 These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis, in which PacifiCorp has an ownership interest of approximately 20%.

2 These coal reserves are mined by PacifiCorp subsidiaries.

3 These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc., a subsidiary of PacifiCorp, and a subsidiary of Idaho Power Company. Pacific Minerals, Inc. has a two-thirds interest in the joint venture.

Coal reserve estimates are subject to adjustment as a result of the development of additional data, new mining technology and changes in regulation and economic factors affecting the use of such reserves.

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Business Review Summary of Key Operating Statistics

Table 3

Ø PacifiCorp Distribution and Transmission Systems Key Information 2004/05

	Pacific Power	Utah Power	Total
Franchise area	72,075 sq miles	63,175 sq miles	135,250 sq miles
System maximum demand	4,018 MW	4,610 MW	8,628 MW
Transmission network (miles)			
Overhead			15,530
Distribution network (miles)			
Underground	5,798	8,705	14,503
Overhead	26,143	17,709	43,852

Table 4

Ø Total Electricity Units Distributed in Pacific Power Service Area (GWh)

Year	Residential	%	Commercial	%	Industrial	%	Other	%	Total
2000/01	7,768	31	7,041	28	10,164	40	130	1	25,103
2001/02	7,537	31	6,932	29	9,743	40	129		24,341
2002/03	7,454	31	7,081	29	9,478	40	90		24,103
2003/04	8,205	33	7,587	31	9,025	36	72		24,889
2004/05	7,889	32	7,507	31	9,230	37	75		24,701

Table 5

Ø Total Electricity Units Distributed in Utah Power Service Area (GWh)

Year	Residential	%	Commercial	%	Industrial	%	Other	%	Total
2000/01	5,687	24	6,593	28	10,495	45	575	2	23,350
2001/02	5,858	25	6,878	30	9,868	43	582	2	23,186
2002/03	5,833	26	6,925	30	9,570	42	541	2	22,869
2003/04	6,256	26	6,826	29	10,109	42	599	3	23,790
2004/05	6,228	26	7,134	29	10,225	42	631	3	24,218

Table 6

Ø Summary of PPM Energy Generating Facilities as at 31 March 2005

	Location	Energy Source		Installation Date	Plant Net Capability (MW)
Thermal electric plants					
Klamath Cogeneration Plant	Klamath Falls, Oregon	Natural gas-fired	Combined cycle	2001	506
West Valley Generating Plant	West Valley City, Utah	Natural gas-fired	Single cycle	2002	200
Klamath Generating Plant	Klamath Falls, Oregon	Natural gas-fired	Single cycle	2002	100
Subtotal (3 thermal electric plants)					**806**

Renewable electric plants				
Phoenix Wind Power Plant	Southern California	Wind generation	1999	3
Stateline Wind Energy Center	Oregon/Washington	Wind generation	2002	300
Klondike Wind Power Plant	Northcentral Oregon	Wind generation	2001	24
High Winds Energy Center	Northern California	Wind generation	2003	162
Southwest Wyoming Wind Energy Center	Southwest Wyoming	Wind generation	2003	144
Moraine Wind Power Plant	Southwest Minnesota	Wind generation	2003	51
Flying Cloud Wind Power Plant	Northwest Iowa	Wind generation	2003	44
Mountain View III Wind Power Plant	Southern California	Wind generation	2003	22
Colorado Green Wind Power Plant	Southeast Colorado	Wind generation	2003	81*
Subtotal (9 renewable electric plants)				**831**
Total all plants (Owned or controlled plants)				**1,637**

* Jointly owned plant; amount shown represents PPM Energy s share only.

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Table 7

Ø Sources of ScottishPower Owned Generating Capacity in the UK and the Republic of Ireland as at 31 March 2005

	Location	Energy Source	Installation Date	Plant Net Capability (MW)
Thermal electric plants				
Longannet	Fife, Scotland	Coal/gas/waste derived fuel	1970	2,304
Cockenzie	East Lothian, Scotland	Coal/oil/biomass	1967	1,152
Brighton	Sussex, England	Natural gas-fired Combined cycle	2000	400
Damhead Creek	Kent, England	Natural gas-fired Combined cycle	2000	800
Knapton	Yorkshire, England	Sour gas-fired Single open cycle	1994	42
Rye House	Hertfordshire, England	Natural gas-fired Combined cycle	1993	715
Subtotal (6 thermal electric plants)				**5,413**
Hydroelectric plants				
Cruachan	Argyll & Bute, Scotland	Pumped Storage	1965	440
Galloway Scheme	Dumfries & Galloway, Scotland	Conventional Hydro	1930s/1985	106
Lanark Scheme	Lanarkshire, Scotland	Conventional Hydro	1920s	17
Subtotal (3 hydroelectric plants)				**563**
Renewable electric plants				
Barnesmore	County Donegal, Republic of Ireland	Wind generation	1997	15
Bienn an Tuirc	Argyll & Bute, Scotland	Wind generation	2001	30
Carland Cross	Cornwall, England	Wind generation	1992	3*
Coal Clough	Lancashire, England	Wind generation	1992	4*
Corkey	County Antrim, Northern Ireland	Wind generation	1994	5
Cruach Mhor	Argyll & Bute, Scotland	Wind generation	2004	30
Dun Law	Midlothian, Scotland	Wind generation	2000	17
Elliots Hill	County Antrim, Northern Ireland	Wind generation	1995	5
Hagshaw Hill	Lanarkshire, Scotland	Wind generation	1995	16
Hare Hill	Ayrshire, Scotland	Wind generation	2000	13
P & L Windfarm	Monmouthshire, Wales	Wind generation	1993	15*
Rigged Hill	County Londonderry, Northern Ireland	Wind generation	1994	5
Subtotal (12 renewable electric plants)				**158**
CHP	Various, England	Combined heat and power (gas-fired)		**102**
Total all plants (Owned or controlled plants)				**6,236**

* Jointly owned plants; amount shown represents ScottishPower s share only.

Table 8

Ø UK Distribution and Transmission Systems Key Information 2004/05

	ScottishPower	Manweb	Total
Franchise area	22,950 km^2	12,200 km^2	35,150 km^2
System maximum demand	4,089 MW	3,055 MW	7,144 MW
Transmission network (km)			
Underground	240		240
Overhead	3,791		3,791

Distribution network (km)			
Underground	38,475	26,186	64,661
Overhead	21,341	21,899	43,240

Table 9

Ø Total Electricity Units Distributed in the ScottishPower Service Area (GWh)

Year	Residential	%	Business	%	Total
2000/01	8,505	38	14,189	62	22,694
2001/02	8,698	39	13,864	61	22,562
2002/03	8,643	39	13,689	61	22,332
2003/04	8,620	39	13,639	61	22,259
2004/05	8,739	39	13,903	61	22,642

Table 10

Ø Total Electricity Units Distributed in the Manweb Service Area (GWh)

Year	Residential	%	Business	%	Total
2000/01	5,460	32	11,826	68	17,286
2001/02	5,387	32	11,540	68	16,927
2002/03	5,512	33	11,233	67	16,745
2003/04	5,862	35	11,018	65	16,880
2004/05	6,310	37	10,880	63	17,190

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In the year, investment, business performance and our hedging strategy all contributed to delivering pre-tax profit, excluding goodwill amortisation and the exceptional item, of over £1 billion for the first time. This performance has been reflected in the dividends for the full year, which have increased by 10% to 22.50 pence.

David Nish Finance Director

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Non-GAAP Financial Measures

*Items marked * are excluding goodwill amortisation and/or the exceptional item. ScottishPower management assesses the underlying performance of its businesses by adjusting UK Generally Accepted Accounting Principles (GAAP) statutory results to exclude items it considers to be non-operational or non-recurring in nature. In the years presented, goodwill amortisation and the exceptional item have been excluded. Therefore, to provide more meaningful information, ScottishPower has focused its discussion of business performance on the results excluding these items. Items marked are non-GAAP liquidity measures, which management and external bodies utilise to assess the performance of our business. In accordance with guidance from the UK Auditing Practices Board, the UK Listing Authority, and the US Securities and Exchange Commission, where non-GAAP figures are discussed, comparable UK GAAP figures have also been discussed and reconciled to the non-GAAP figures. A detailed Cautionary Statement Regarding Non-GAAP Financial Information is provided in Section 18 on page 72. The full statutory results are presented in the Group Profit and Loss Account and in Note 1 Segmental profit and loss information on page 112 and on page 116, respectively.*

before tax, both excluding goodwill amortisation and the exceptional item, exceeding £1 billion*. The group comprises four businesses operating in both a regulated and competitive environment in the UK and US, which serve over 6.7 million (2003/04: 5.8 million) electricity and gas customers. The group considers its core strengths to lie in a number of key areas, including strong asset management skills; its integrated approach to energy and risk management; a dedicated customer service focus; and careful management of regulatory partnerships.

The regulated businesses accounted for 39% of group external turnover in the current year (2003/04: 46%), and 80%* of operating profit, excluding goodwill amortisation and the exceptional item (2003/04: 88%*). The group s geographical distribution of operating profit, excluding goodwill amortisation and the exceptional item, is broadly balanced between its UK and US operations. The regulated businesses comprise PacifiCorp in the US and Infrastructure Division in the UK. Together they accounted for almost £2.7 billion of group turnover in the year, and almost £960 million* of operating profit, excluding goodwill amortisation and the exceptional item. PacifiCorp is a regional vertically integrated utility servicing 1.6 million customers in six US states and is subject to the jurisdiction of the public utility regulatory authorities in each of these states. At operating profit level, excluding goodwill amortisation and the exceptional item, it is the largest of our divisions. Infrastructure Division, our UK wires business,

1 Introduction

ScottishPower is an international energy business, listed on both the London and New York Stock Exchanges, with 2004/05 annual turnover of £6.8 billion and operating profit and profit

owns and manages a substantial UK electricity transmission and distribution network covering approximately 112,000 km within the ScottishPower and Manweb franchise service areas. The division comprises three asset-owner companies , which hold the group s UK regulated assets and transmission and

* *Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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Financial Review

distribution licences, and an asset-management company, which provides the expertise necessary to conduct the day-to-day operation of the network. At an operating profit level, excluding goodwill amortisation and the exceptional item, the Infrastructure Division is our second largest division.

The competitive businesses are the UK Division and PPM Energy in the US. Together they contributed almost £4.2 billion of group turnover in the year, and just under £240 million* of operating profit, excluding goodwill amortisation. The UK Division is an integrated commercial energy generation and supply business, which balances and hedges energy demand from a diverse generation portfolio through to a national customer base of over 5.1 million customers. The UK Division owns, controls and operates over 6,200 MW of generating capacity, comprising coal, gas, hydroelectric and wind power generation assets, giving the division a particularly flexible portfolio. PPM Energy commenced substantive operations in 2001 and supplies energy from clean and efficient natural gas and wind generation facilities and provides gas storage services to wholesale customers, located in the mid-western and western US and Canada. PPM Energy has approximately 1,600 MW of thermal and renewable generation currently under its

Table 11

Key drivers

PacifiCorp

- Achieving allowed regulatory rate of return on equity
- Managing the regulatory rate case process
- Managing a balanced power position
- Managing the impact of growing demand
- Improving operating and capital cost-efficiency

Infrastructure Division

- Maximising returns from investment in the regulatory asset base
- Securing a positive outcome from the 2007 Transmission Price Review and delivering outperformance against the 2005 Distribution Price Control
- Improving operating and capital cost-efficiency

PPM Energy

- Availability of attractive business opportunities and favourable public policies

UK Division

- Continuing to grow the customer base at optimal tariff levels

- Optimising returns from its gas and power portfolio by actively seeking to lock in value inherent in the portfolio s assets and contracts

- Managing a balanced power position

- Further significant expansion of renewable generation at appropriate rates of return

- Improving operating and capital cost-efficiency

* *Non-GAAP performance measure (see* *Cautionary Statement Regarding Non-GAAP Financial Information* *on page 72)*

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ownership or control, with a further 574 MW of wind power due on-line by December 2005.

The group s results are affected to a small extent by seasonality, with group external turnover and operating profit weighted towards the second half of the year, primarily as a result of higher winter demand requirements in the UK, with complementary summer and winter seasonal load patterns in the US. Seasonality has had the greatest impact on the UK Division s results, where, historically, customer demand has peaked during the winter months reflecting increased heating and lighting requirements.

The businesses key drivers impacting the financial performance of the group are shown in Table 11. Other factors affecting our financial performance include increases and reductions in customer demand for electricity, economic growth and downturns, and abnormal weather, all of which impact revenues, cash flows and investment. The group proactively manages its supply and demand balance, but any unanticipated changes in future customer demand, weather conditions, generation resource availability or commodity prices may affect revenues from, and the cost of, supplying power to customers.

ScottishPower is committed to its strategy of investing for growth and improving operational performance. During the year, the ScottishPower Board undertook a strategic review of PacifiCorp and concluded in May 2005 that shareholders interests were best served by a sale of PacifiCorp and the return of capital to shareholders.

In the year, group operating profit reduced by £870 million to £153 million principally due to an exceptional impairment charge of £927 million, which reduced the book value of PacifiCorp down to its expected net realisable value.

Further details of the sale and impairment charge are provided in Section 3 on page 40.

In the year, ScottishPower continued with its significant investment programme and group operating profit, excluding goodwill amortisation and the exceptional item, increased by 4%*. The Infrastructure Division has delivered growth in the year with operating profit up by 6% on last year, but PacifiCorp s operating profit*, excluding goodwill amortisation and the exceptional item, reduced due to a combination of unfavourable weather, lower generation availability and the effect of the weaker dollar on sterling results. The competitive businesses reported substantial improvements, with operating profit, excluding goodwill amortisation, up by 74%* in the year. In the UK Division, this has been achieved through customer growth combined with investment in, and successful integration of, new generation and an effective hedging strategy; and in PPM Energy through 2003/04 investment in new wind resources, gas storage activities and optimisation of long-term contractual arrangements.

ScottishPower is committed to maintaining an A category credit rating for its principal operating subsidiaries, thereby allowing access to flexible borrowing sources at favourable cost. To achieve this rating, on completion of the sale of PacifiCorp, the group will target credit ratios of adjusted Funds From Operations (FFO)/net debt of greater than 25% and FFO/interest cover of more than five times. ScottishPower will work closely with the rating agencies in order to ensure its rating objectives are achieved. In addition to the cash generated from operations and existing cash resources, the group relies on the capital markets as a source of liquidity to fund investment as required. Consistent with this strategy, the group successfully issued $1.5 billion of US bonds in March 2005, and unwound a corresponding amount of derivative hedges.

The group seeks to minimise and manage earnings volatility whilst protecting the value of the group s overseas assets

** Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

through appropriate interest rate and foreign exchange risk management programmes. Against these objectives, the effective use of dollar denominated debt, derivatives and commodity price hedging have substantially protected the group s earnings and net assets from foreign exchange volatility over the past 12 months, while allowing the group to benefit from interest rates in dollars that have been lower than those in sterling. Substantially all of the group s US investments continue to be protected from exchange rate movements, with expected US earnings similarly protected in the next financial year.

During the year, earnings per share were lower by 46.23 pence resulting in a loss per share of 16.83 pence due to the exceptional goodwill impairment charge. Excluding goodwill amortisation and the exceptional item, earnings per share increased by 10% to 40.22 pence*, as a result of the continuing three businesses improved performance and lower group interest charges. Key financial highlights are shown in the chart on page 39.

ScottishPower will adopt International Financial Reporting Standards (IFRS) for the financial year ending 31 March 2006. Included within the IFRS Financial Information section on page 173 are reconciliations of the group s 2004/05 UK GAAP financial statements to the amounts that would have been reported under IFRS (based on the IFRS standards and interpretations currently in existence). ScottishPower has elected to defer the application of the financial instruments standards (International Accounting Standard (IAS) 32 Financial Instruments: Disclosure and Presentation and IAS 39 Financial Instruments: Recognition and Measurement) until the financial year ending 31 March 2006, and therefore, there is no impact from these standards on the 2004/05 IFRS financial information. The implementation of IFRS is discussed in more detail in Section 14 on page 64.

2 Dividend Policy

Our intention is to target dividend cover based on full year earnings within a range of 1.5 to 2.0 times and ideally towards the middle of that range. This excludes goodwill amortisation and exceptional items. We have achieved that with our full year dividend of 22.50 pence per share, which is covered 1.79 times by earnings per share, excluding goodwill amortisation and the exceptional item, of 40.22 pence*. We aim to grow dividends broadly in line with earnings and we expect to continue this policy following the sale of PacifiCorp and the return of capital to shareholders. In the absence of unforeseen circumstances, ScottishPower intends to pay an identical dividend for each of the first three-quarters of 2005/06, of 5.20 pence per share per quarter, representing an increase of 5% from 2004/05. The balance of the total dividend for 2005/06 will be set in the fourth quarter.

3 Sale of PacifiCorp

During the year, the ScottishPower Board undertook a strategic review of PacifiCorp, as a result of its performance and the significant investment it required in the immediate future. In May 2005, the Board concluded that, in the light of the scale and timing of the capital investment required in PacifiCorp and the likely profile of returns from that investment, shareholders interests were best served by a sale of PacifiCorp and return of capital to shareholders. The Board therefore announced on 24 May 2005 that ScottishPower had entered into a binding agreement for the sale of PacifiCorp to MidAmerican for $9.4 billion. The Board intends to return approximately $4.5 billion of the net proceeds of $5.0 billion from the sale of PacifiCorp, to shareholders. The sale is subject to regulatory and shareholder approval.

An exceptional impairment charge of £927 million has been made in the year, to reduce the book value of PacifiCorp, under UK GAAP, down to its expected net realisable value. Pending completion of the sale, PacifiCorp will be treated as a discontinued operation in the financial statements of ScottishPower. The impairment amount excludes foreign exchange gains of £485 million, achieved to date, which will be reflected in ScottishPower s Income Statement under IFRS on completion of the sale of PacifiCorp to MidAmerican.

The sale is subject to, among other things, Securities and Exchange Commission (SEC), Department of Justice or Federal Energy Regulatory Commission (FERC), Federal Trade Commission and Nuclear Regulatory Commission approvals at the federal level, without conditions that would have a material adverse effect on the PacifiCorp business. In addition it is subject to approval at state level in Utah, Oregon, Wyoming, Washington, Idaho and California provided such state approvals are not subject to conditions whose effect would be meaningfully adverse to the business of PacifiCorp. ScottishPower anticipates that such approvals should be forthcoming within 12 to 18 months.

Between now and closing of the sale, ScottishPower has agreed to invest additional equity in PacifiCorp to fund ongoing capital expenditure in line with PacifiCorp s current plan. Pursuant to these arrangements, ScottishPower will invest $500 million during the financial year 2005/06. In addition ScottishPower has agreed to make further investments during the financial year 2006/07 of up to $525 million, contributed quarterly, although ScottishPower will be fully compensated for any such payments made in respect of the financial year 2006/07. Between now and the closing of the sale, ScottishPower is entitled to dividends from PacifiCorp in line with PacifiCorp s current plan. Pursuant to these arrangements, it is expected that, ScottishPower will receive $215 million of dividends during the financial year 2005/06, and $242 million of dividends during the financial year 2006/07, these amounts to accrue monthly.

The sale of PacifiCorp enables ScottishPower to focus its

** Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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management and capital on the continued development of the Infrastructure Division, UK Division and PPM Energy. These businesses have driven our profit growth over the last two years and delivered overall returns ahead of our cost of capital. We consider these businesses to have substantial opportunities for continued growth through capital investment and improved operational performance.

4 Overview of the Year to March 2005

Group Profit and Loss

This has been a year of profitable growth for the Infrastructure Division, UK Division and PPM Energy, which all delivered strong performances. PacifiCorp s results were affected by the impact of weather conditions, which reduced demand and owned hydroelectric generation availability. Thermal plant outages, particularly in the first half, also contributed to higher net power costs. During the year, an exceptional goodwill impairment charge of £927 million has been made in ScottishPower s results to reduce the book value of PacifiCorp down to its expected net realisable value. As a result of this charge, the group recorded a pre-tax loss of £29 million, compared to a pre-tax profit of £792 million in 2003/04. Excluding goodwill amortisation and the exceptional item, pre-tax profit increased by 10% to over £1 billion*, as improved performances from our continuing three businesses and substantially lower interest charges, more than offset the impact of PacifiCorp s lower operational results. Our policy to hedge both dollar earnings and net assets to reduce the impact of currency volatility, continued to successfully mitigate the impact of the weaker US dollar. At operating profit level, an earnings hedge benefit of approximately £53 million (2003/04: £60 million) was delivered and our balance sheet hedging delivered an £88 million (2003/04: £39 million) benefit to interest from the UK/US interest rate differential.

Group turnover for the year to 31 March 2005 was £6,849 million, an increase of £1,052 million on the previous year, with the majority of the increase in the UK Division. The weaker US dollar reduced sterling revenues by £225 million, net of the movement in hedging benefits from the forward sale of dollars. The effect of the weaker dollar on PacifiCorp and PPM Energy s sterling revenues was mitigated at an earnings level by the favourable effect of the weaker dollar on costs and by our hedging strategy.

PacifiCorp s turnover for the year was down by £37 million at £2,282 million mainly as a result of a £205 million adverse translation impact of the weaker US dollar. PacifiCorp s dollar turnover increased by 8% primarily as a result of higher wholesale volumes associated with energy balancing, which was offset by increases in purchase costs. PacifiCorp s retail revenues increased to a lesser extent, mainly as a result of regulatory rate increases and customer growth. Infrastructure Division s external turnover grew by £22 million to £380 million (6%) due to higher regulated and new connections business revenues, both driven by higher volumes. The UK Division experienced turnover growth of 33%, with revenues rising by £908 million to £3,685 million mainly as a result of higher retail sales, increased energy balancing activities in England & Wales, which was offset in cost of sales, and the acquisition of new generation plant. PPM Energy s turnover increased by £159 million to £502 million, after a £20 million adverse US dollar translation impact. PPM Energy s dollar turnover was higher by 56%, as a result of increased sales under long-term contracts, activities around owned and contracted gas storage and the addition of new wind generation.

Cost of sales of £4,567 million increased by £937 million on last year, reflecting growth in balancing our UK and PacifiCorp energy positions; increased power production and purchase costs in both the UK Division and PacifiCorp; the acquisition of generation plant in the UK; and increased gas activities and wind generation at PPM Energy. These increases were partly offset by the favourable US dollar translation impact. **Transmission and distribution costs** increased by £62 million to £606 million as a result of higher UK Division costs associated with customer growth and higher PacifiCorp labour-related costs and increased depreciation, partly offset by the favourable US dollar translation impact. **Administrative expenses (including goodwill amortisation and the exceptional item)** as shown in Table 12 were £930 million higher than last year at £1,556 million. Excluding goodwill amortisation and the exceptional item, administrative expenses increased by £13 million* due to higher labour-related costs in the US, including costs to support business growth in PPM Energy; and operating costs associated with customer growth and new generation plants in the UK Division. Partly offsetting this was the release of an environmental provision within PacifiCorp and the favourable US dollar impact. **Depreciation**, which is included within each of the three preceding cost categories, was £19 million higher than last year at £458 million. Increased levels of capital investment throughout the group resulted in higher depreciation charges during the year, partly offset by the impact of the weaker dollar on translation

Ø **Table 12**

Administrative expenses (£m)

	2004/05	2003/04
Administrative expenses	**1,555.8**	626.2
Goodwill amortisation	**(117.5)**	(128.0)
Exceptional item	**(927.0)**	
Administrative expenses excluding goodwill and exceptional*	**511.3**	498.2

** Non-GAAP performance measure (see   Cautionary Statement Regarding Non-GAAP Financial Information   on page 72)*

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Financial Review

As shown in Table 13 **group operating profit** decreased by £870 million to £153 million principally due to the exceptional charge in the year of £927 million, relating to the impairment of goodwill associated with PacifiCorp. Excluding goodwill amortisation and the exceptional item, group operating profit increased by £46 million to £1,197 million* (4%), after an adverse foreign exchange effect of £58 million. These results reflect a strong performance in our UK operations and good growth in PPM Energy, with combined operating profit, excluding goodwill amortisation, up by over 23%* on last year. Although its results were below expectations for the year, PacifiCorp delivered an improved second half operational performance compared to the first half of the year.

In PacifiCorp, operating profit, excluding goodwill amortisation and the exceptional item, was lower by £78 million at £542 million*, as a result of adverse weather conditions, lower generation availability and a £61 million unfavourable net translation variance arising from the weaker US dollar and reduced hedging benefits. Infrastructure Division s operating profit showed an increase of £23 million (6%) to £416 million, primarily from higher regulated revenues and lower net operating costs. The UK Division s operating profit, excluding goodwill amortisation, improved by £79 million to £180 million* due to continued customer growth, investment in generation and effective management of its resource portfolio. In PPM Energy, operating profit, excluding goodwill amortisation, increased by £22 million to £59 million*, primarily from contributions from gas storage activities and investments in wind generation.

Ø **Table 13**

Group operating profit (£m)

	2004/05	2003/04
Operating profit	**152.6**	1,022.6
Goodwill amortisation	**117.5**	128.0
Exceptional item	**927.0**	
Operating profit excluding goodwill and exceptional*	**1,197.1**	1,150.6

Goodwill amortisation of £117 million was £11 million lower than last year as a result of the translation impact of the weaker US dollar reducing the goodwill charge.

The **net interest** charge reduced by £50 million to £188 million for the year and included a £14 million translation benefit from the weaker US dollar and an additional £49 million benefit from the UK/US interest rate differential arising from our dollar balance sheet hedging strategy, whereby the group swaps out of sterling liabilities into dollar liabilities in floating rate debt and interest payable on capital contributions to be refunded under the new British Electricity Trading and Transmission Arrangements (BETTA). Further discussion on interest charges is given within the Liquidity and Capital Resources section on page 53.

As shown in Table 14, the **loss before tax** was £29 million compared to a profit before tax of £792 million last year. The loss before tax was due to the exceptional goodwill impairment charge. Excluding goodwill amortisation and the exceptional item, profit before tax improved by £95 million to £1,015 million* (10%), with the impact of PacifiCorp s results being more than offset by operating profit improvements in our other businesses and the lower net interest charge. A foreign exchange hedge benefit of approximately £53 million (2003/04: £60 million) was delivered from selling forward our forecast dollar earnings at a favourable rate compared to the average rate for the year. This has helped protect group profit from the effect of the weaker US dollar.

Ø **Table 14**

(Loss)/profit before tax (£m)

	2004/05	2003/04
(Loss)/profit before tax	**(29.3)**	792.1
Goodwill amortisation	**117.5**	128.0
Exceptional item	**927.0**	
Profit before tax excluding goodwill and exceptional*	**1,015.2**	920.1

The **tax charge** for the year increased by £26 million to £274 million, on the loss before tax of £29 million. The tax charge increased as a result of higher pre-tax profit, excluding the exceptional goodwill impairment charge, which had no impact on the tax charge for the year. Excluding goodwill amortisation and the exceptional item, the effective rate of tax remained unchanged for the year at 27%*. As shown in Table 15, the effective rate of tax is calculated by dividing the tax charge by profit before tax, expressed as a percentage. The effective rate of tax is dependent on a number of factors. The mix of profit impacts the rate because of the higher rates applied to taxable profit in the US (around 38%) when compared to the UK (30%). A change in the proportion of profit earned in the US, therefore, results in a change in the group s effective tax rate. The effective rate, excluding goodwill amortisation and the exceptional item, is lower than the statutory rate because the group seeks to carry out its commercial activities in a tax efficient manner and benefits from the group s financing arrangements. Where the tax treatment of a specific item is debatable, the group makes realistic provision for the tax payable and will endeavour to negotiate a settlement with the tax authorities, which is not less favourable than the accounting treatment of the item. As a result, when some of these items are agreed, the release of any balance of the provision will reduce the effective tax rate. In the current year, the effective tax rate order to hedge its US dollar denominated net assets. The net interest charge also benefited from £14 million of net interest receipts following the settlement of outstanding tax claims. These reductions were partly offset by £27 million of increased charges, which primarily related to higher interest payments on

** Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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benefited from increased Production Tax Credits (PTCs) associated with our windfarm investment programme in the US, with net movements on provisions, including the impact of the group s internal financing arrangements, broadly in line with last year. Legislation, proposed in the Finance Bill 2005 but not yet enacted, is likely to affect the group s internal financing arrangements and could, therefore, result in an increase in the effective rate in future years. However, higher PTCs from US windfarms are expected partly to offset this increase.

Ø **Table 15**

Effective rate of tax (£m)/(%)

	2004/05	2003/04
Tax charge	**274.1**	248.4
(Loss)/profit before tax	**(29.3)**	792.1
Effective rate of tax	**(935)%**	31%
Profit before tax, excluding goodwill and exceptional*	**1,015.2**	920.1
Effective rate of tax, excluding goodwill and exceptional*	**27%**	27%

The **loss after tax**, as shown in Table 16, was £303 million compared to a profit after tax of £544 million for the prior year. Excluding goodwill amortisation and the exceptional item, profit after tax grew by £69 million (10%) to £741 million*, with our strong operating results in the UK businesses and PPM Energy and lower interest charges, being partly offset by higher tax charges.

Ø **Table 16**

(Loss)/profit after tax (£m)

	2004/05	2003/04
(Loss)/profit after tax	**(303.4)**	543.7
Goodwill amortisation	**117.5**	128.0
Exceptional item	**927.0**	
Profit after tax excluding goodwill and exceptional*	**741.1**	671.7

Earnings per share, as shown in Table 17, were lower by 46.23 pence resulting in a loss per share of 16.83 pence for the year. Excluding goodwill amortisation and the exceptional item, earnings per share increased by 3.82 pence (10%) to 40.22 pence*.

Ø **Table 17**

(Loss)/earnings per share (pence)

	2004/05	2003/04
(Loss)/earnings per share (EPS)	**(16.83)**	29.40
EPS impact of goodwill amortisation*	**6.42**	7.00
EPS impact of the exceptional item*	**50.63**	
EPS excluding goodwill and exceptional*	**40.22**	36.40

The full year **dividends** were 22.50 pence per share and were covered 1.79 times by earnings per share, excluding goodwill amortisation and the exceptional item, of 40.22 pence*.

Cash Flow and Net Debt

Cash flows from operating activities reduced by £104 million to £1,260 million for the year as favourable operating performance was partly offset by higher working capital commitments, mainly due to higher debtors reflecting significant customer growth in our UK Division, and provision movements. Interest, tax and dividend payments totalled £600 million, with the tax and interest payments substantially lower than last year due to the settlement of outstanding tax claims and cash benefits associated with our hedging strategy. Net inflows from the sale of tangible fixed assets, fixed asset investments and disposals were £30 million. Financing net inflows, other than changes in net debt, were £227 million, mainly as a result of the cash received on the maturity and cancellation of net investment hedging derivatives during the year. These cash flows combined provided cash of £917 million, which contributed to the group s net capital investment cash spend of £1,270 million. After adverse non-cash movements of £70 million, which included debt acquired following the purchase of the remaining 50% of the Brighton power plant partly offset by the favourable effect of foreign exchange, **net debt** was £4,147 million at 31 March 2005, £423 million higher than at 31 March 2004. Gearing (net debt/equity shareholders funds) was 104%, compared to 79% at 31 March 2004.

Investment

Our investment strategy is to drive the growth and development of our regulated and competitive businesses, through a balanced programme of capital investment. Investments in our regulated businesses aim to achieve at least the allowed rate of regulatory returns and our competitive businesses are expected to achieve returns of at least 300 basis points above each division s weighted average cost of capital. All investments are assessed on a risk adjusted returns basis, are expected to be earnings enhancing and should support our aim to retain our A category credit rating for our principal operating subsidiaries.

In the year, the group invested £1,377 million in its asset base. Of this, £1,013 million related to fixed asset additions and £415 million related to acquisitions and fixed asset investments (including Damhead Creek and Brighton power plants in the UK, and Atlantic Renewable Energy Corporation (AREC) and investments associated with the Maple Ridge joint venture in the US), offset by £51 million of customer grants and contributions.

Of our net capital investment for the year, £831 million (60%) was invested for growth and £546 million was invested in

** Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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refurbishment, upgrade and other projects. Growth investment included the acquisitions in the UK of the 800 MW Damhead Creek power plant for £320 million and the remaining 50% of the 400 MW Brighton power plant for £71 million. Other growth investment totalled £440 million and included: windfarm development spend of £142 million in the UK and the US; network expansion and reinforcement spend of £152 million in the UK and US; and £136 million on the 525 MW Currant Creek and 534 MW Lake Side power plants in Utah.

Of the £831 million invested for growth expenditure, £298 million (36%) was invested in our regulated businesses and £533 million (64%) in our competitive businesses. Geographically, £310 million (37%) of growth spend was invested in the US and £521 million (63%) in the UK. The £546 million balance of refurbishment and upgrade spend was split £254 million in the US (47%) and £292 million in the UK (53%).

Our level of capital investment is expected to grow to approximately £1.5 billion next year, based on a US dollar/UK sterling exchange rate of approximately $1.80, with some £1.0 billion relating to the continuing three businesses. This will enable the businesses to optimise the performance of existing assets and pursue growth opportunities through a balanced programme of expenditure.

Business Reviews

PacifiCorp

PacifiCorp is our US regulated business which seeks to maximise its return on equity (ROE), within the limits permitted by US state regulators. The outcome of general rate cases conducted by the state regulatory commissions sets PacifiCorp s revenue requirement and prices, and sometimes specifies an authorised ROE. Regulatory returns for PacifiCorp through the last reportable period at September 2004, were approximately 7% on a normalised basis compared to approximately 8% at September 2003. The current period does not include the increased revenue from the Utah general rate case settlement effective in March 2005 and the Washington general rate case outcome from November 2004. Successful management of the regulatory ratemaking process, maximising the returns on new investment and the recovery of costs through rate setting are key priorities for PacifiCorp to move towards achieving its allowed regulatory rate of return. PacifiCorp is currently pursuing a regulatory programme in all states in which it operates, with the objective of keeping rates closely aligned to ongoing costs and, in the year, has been awarded approximately $75 million of additional annual revenue from rate cases. Over the winter months there was less snow and rainfall than normal, which will reduce hydroelectric generation availability during the first six months of 2005/06. PacifiCorp is seeking to account for and recover power costs in Oregon and Washington related to these unfavourable weather conditions.

Pending completion of its sale, PacifiCorp will be treated as a discontinued operation in the group s 2005/06 financial statements.

PacifiCorp s key customer statistics are shown in Table 18 and key financial information in Table 19.

Ø **Table 19**

PacifiCorp (£m)

	2004/05	2003/04
External turnover	**2,281.5**	2,318.6
Operating (loss)/profit	**(497.4)**	496.8
Goodwill amortisation	**112.1**	122.5
Exceptional item	**927.0**	
Operating profit excluding goodwill and exceptional*	**541.7**	619.3

Ø **Table 18**

PacifiCorp customer statistics

		2004/05	2003/04	Change	% Change
Energy sales					
Residential	GWh	14,117	14,460	(343)	(2)%
Commercial	GWh	14,642	14,413	229	2%
Industrial	GWh	19,454	19,133	321	2%
Other	GWh	706	673	33	5%
Total retail electricity	**GWh**	**48,919**	**48,679**	**240**	

Wholesale electricity	**GWh**	**29,080**	**24,464**	**4,616**	**19%**
Customer numbers					
Residential	thousands	1,373	1,341	32	2%
Commercial	thousands	194	190	4	2%
Industrial	thousands	34	34		
Other	thousands	4	5	(1)	(20)%
Total	**thousands**	**1,605**	**1,570**	**35**	**2%**
Residential customers					
Average annual usage	kWh	10,411	10,889	(478)	(4)%
Average annual revenue per customer[1]	$	741	749	(8)	(1)%
Revenue per kWh[1]	cents	7.1	6.9	0.2	3%

[1] Excludes recovery of deferred power costs

* *Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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Turnover in PacifiCorp reduced by £37 million to £2,282 million in the year, mainly because of the £205 million adverse translation impact of the weaker US dollar. Dollar turnover increased by $312 million (8%) to $4,125 million with the majority of the increase attributable to wholesale volumes, which increased by 4,616 GWh to 29,080 GWh and higher retail revenues from regulatory rate increases.

Wholesale revenue increased by $240 million in the year, of which $199 million was due to higher energy sales volumes on short-term contracts, mainly associated with energy balancing, and $108 million was from higher electricity prices on short-and long-term wholesale transactions. These increases were partly offset by a reduction of $67 million, primarily associated with lower energy sales volumes on long-term contracts due to contract expiration. Residential, commercial and industrial revenues grew by $100 million (4%) and retail customer numbers increased by 35,000 to 1.6 million. Residential revenues increased by $10 million, despite a reduction in volumes of 343 GWh to 14,117 GWh, as rate increases and growth in average customer numbers more than offset the impact of lower average estimated customer usage, which reduced to 10,411 kWh compared to 10,889 kWh in the year to March 2004, due primarily to milder weather. Commercial revenues and volumes increased by $40 million and 229 GWh respectively, whilst industrial revenues and volumes increased by $49 million and 321 GWh as a result of regulatory rate increases and growth in average customer numbers. These increases were offset by a reduction of $44 million in the recovery of deferred power costs, which will fully expire by the end of December 2005. Other revenues increased by $16 million primarily due to higher demand-side management and wheeling revenues.

In the year, PacifiCorp reported an operating loss of £497 million, compared to an operating profit of £497 million last year, principally due to the £927 million exceptional charge. Excluding goodwill amortisation and the exceptional item, PacifiCorp s operating profit fell by £78 million to £542 million*, with a £61 million unfavourable net translation variance arising from the weaker US dollar and reduced hedging benefits. Dollar operating profit, excluding goodwill amortisation and the exceptional item, reduced by $29 million to $914 million* as improved retail revenues and benefits from operating efficiency initiatives were offset by increased net power costs and higher net operating costs.

Retail and other regulatory revenues improved operating profit by $98 million before taking into account the expected reduction in deferred power cost recoveries of $44 million. The underlying revenue growth reflected increases in regulatory rates of $92 million and customer growth of $39 million, partly offset by lower customer usage of $33 million, mainly as a result of the milder weather.

Net power costs increased by $98 million largely as a result of the impact of higher market prices on increased purchase volumes due to retail load growth and additional requirements which arose from the impact of unfavourable weather and outages on PacifiCorp s generation portfolio. Higher than average temperatures and lower than normal snow pack and rain levels adversely impacted PacifiCorp s owned hydroelectric facilities, with output decreasing by 13.4% in the year. However, this was mitigated by purchased hydro generation and streamflow hedging arrangements. Although output from PacifiCorp s thermal plants decreased by less than 1% in the year, the cost of replacing the lower output with higher-priced market purchases adversely impacted net power costs.

Operating efficiency initiatives delivered $42 million of benefits in the year and the total benefits delivered to date now exceed the $300 million target. Other net revenue and cost movements were adverse by $37 million, largely as a result of higher labour-related and maintenance costs. Non-recurring items were $10 million higher in the year as the $56 million environmental liability provision release, following the completion of a detailed environmental exposure study, more than offset $46 million of non-recurring items in the prior year.

PacifiCorp s net capital investment was £480 million for the year, with £231 million (48%) invested for organic growth. Of this, £136 million was invested in building new generation. The first phase of the 525 MW Currant Creek combined cycle plant, representing 280 MW, will be operational in summer 2005, with full operations scheduled to begin in summer 2006. Construction at the 534 MW Lake Side combined cycle plant is scheduled to begin in summer 2005. A further £95 million was invested in new connections and network reinforcement and included improvement projects in targeted areas, particularly along Utah s Wasatch Front, where there has been rapid growth in demand for electricity.

Infrastructure Division

Infrastructure Division is our UK regulated wires business and is subject to price controls based on an allowed regulatory rate of return, which was 6.5% for 2004/05. In December 2004, Ofgem s electricity distribution price control proposal, which will apply to our distribution businesses over the next five years from 1 April 2005, was accepted. Our transmission business also accepted the extension of Ofgem s price control for the next two years from 1 April 2005. At these reviews, the methodology for determining the allowed regulatory rate of return changed from a pre-tax basis using a traditional tax wedge , to a post-tax approach to the cost of capital, with a separate tax allowance for individual companies. On a comparable basis with 2004/05, the regulatory rate of return going forward would be 6.9%. Taking account of the methodology changes, the pre-tax cost of capital will be in excess of 8%. The price review outcomes are the result of working closely and constructively with Ofgem to reach agreement. The Infrastructure Division will benefit from increases in allowed revenue as a result of the reviews, with revenues

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Ø **Table 20**
Infrastructure Division network statistics

		2004/05	2003/04	Change	% Change
Electricity units distributed					
ScottishPower service area	GWh	22,642	22,259	383	2%
Manweb service area	GWh	17,190	16,880	310	2%
Total	**GWh**	**39,832**	**39,139**	**693**	**2%**

increasing by around £60 million in 2005/06 mainly due to increased revenue allowances for taxation, and pension costs and also reflecting higher capital investment levels. On 1 April 2005, BETTA was successfully introduced with National Grid assuming operational control of the Great Britain transmission system, including balancing of generation and demand in Scotland. ScottishPower retains network ownership and all associated responsibilities, including development of the network.

Infrastructure Division s network statistics are shown in Table 20 and key financial information in Table 21.

Ø **Table 21**
Infrastructure Division (£m)

	2004/05	2003/04
External turnover	**380.1**	358.3
Operating profit	**416.3**	393.6

In the year, Infrastructure Division s external turnover increased by £22 million to £380 million. External turnover accounts for just over half of Infrastructure s total turnover, as a significant proportion of the division s sales are internal to our UK Division. External electricity revenues increased by £10 million in the year mainly as a result of higher distribution sales volumes. Electricity units distributed increased by 693 GWh or 2% in the year. Other external revenues have grown by £12 million, primarily as a result of higher new connections business revenues, also driven by higher volumes.

Infrastructure Division reported operating profit improved by £23 million to £416 million for the year. Net regulated transmission and distribution use of system revenues increased by £13 million mainly as a result of distribution sales volume growth and favourable transmission prices, in line with allowed revenues. Underlying net costs were favourable by £14 million mainly due to a reduction in third party transmission charges and lower other net costs. This upside, together with a net £4 million favourable movement in one-off gains (relating to a £5 million share of the gain on disposal of gas assets and a £6 million rebate received from the National Grid Company, partly offset by £7 million of lower property gains in the current year), more than offset an £8 million increase in rates and depreciation.

Infrastructure Division s net capital investment was £267 million for the year, with £67 million (25%) invested for organic growth, including expenditure on the connection to the Black Law windfarm and other new customer connections. Other organic investment focused on network reinforcement projects, including the five-year Liverpool city centre regeneration programme and initial spend on the Renewable Energy Transmission Study upgrade programme required to accommodate the connection of renewable generation in Scotland.

As a result of the Distribution Price Control Review, capital expenditure allowances increase by about 55% over the next five years, against the previous control period, with some 1,800 km of overhead lines due to be built. New initiatives in operational excellence will also help the drive towards a 30% improvement in network performance, resulting in reduced fault duration for customers and minimising the risk of financial penalty from Ofgem.

UK Division

The UK Division is our competitive UK business, and is committed to delivering value from its substantial customer base and to increasing its renewable energy portfolio. Investment in generation plant has complemented significant customer growth of 865,000 this year and has also contributed to the increase in profit of the division. Customer numbers continue to grow, albeit at a slower rate than experienced in the first nine months of 2004/05, with an ongoing focus on gaining profitable customers that will create shareholder value.

UK Division s key financial information is shown in Table 22 and key customer statistics in Table 23.

Ø **Table 22**
UK Division (£m)

	2004/05	2003/04
External turnover	**3,685.1**	2,777.4
Operating profit	**175.6**	96.1
Goodwill amortisation	**4.9**	4.9
Operating profit excluding goodwill*	**180.5**	101.0

UK Division s turnover increased by £908 million to £3,685 million for the year, due to a number of factors. Strong volume growth in electricity and gas turnover was experienced as a result of customer gains, particularly within the domestic gas and out-of-area electricity markets. Volumes of wholesale electricity sales in England & Wales increased which, as part of the division s energy balancing activities, were offset by

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Ø **Table 23**

UK Division customer statistics

			2004/05	2003/04	Change	% Change
Energy sales						
Retail electricity		GWh	28,034	25,300	2,734	11%
Wholesale electricity balancing	England & Wales	GWh	32,998	25,577	7,421	29%
Retail gas		millions of Therms	1,321	987	334	34%
Customer numbers						
Electricity and gas customers		thousands	5,115	4,250	865	20%
Domestic electricity customers						
Home area retention		%	61	60	1	2%
Average annual usage		kWh	5,084	5,070	14	
Average annual revenue per customer		£	357	340	17	5%
Revenue per kWh		pence	7.0	6.7	0.3	4%
Domestic gas customers						
Average annual usage		Therms	715	688	27	4%
Average annual revenue per customer		£	339	299	40	13%
Revenue per Therm		pence	47	43	4	9%

increases in purchase costs. The recent generation plant acquisitions also contributed significantly to turnover volume growth. Turnover benefited to a lesser extent by increased prices in both wholesale and domestic retail activities.

Retail electricity sales improved by £281 million primarily as a result of increased domestic volumes due to out-of-area customer gains, with business volume growth and increased tariffs contributing to a lesser extent. Retail electricity volumes increased by 11% to 28,034 GWh for the year. Retail gas turnover improved by £154 million due to customer growth and, to a lesser extent, tariff increases. Retail gas volumes improved by 34% to over 1.3 billion therms.

Wholesale electricity sales in England & Wales, entered into for balancing activity purposes, increased by £259 million in the year to £758 million, as prices continued to recover and volumes increased by 7,421 GWh to 32,998 GWh. The volume growth was due to the division balancing its energy position more actively to minimise exposure to uncertain balancing mechanism prices and to protect against long-term price volatility. The increase in turnover caused by this activity was offset by a corresponding increase in purchase costs and as a result had minimal impact on operating profit. Damhead Creek (which was acquired in June 2004) and Brighton (of which the remaining 50% was acquired in September 2004) added £162 million of turnover during the year.

Other revenues, including agency wholesale electricity and gas revenues, increased by £52 million in the year. Agency electricity turnover increased as a result of higher-priced generation sales to third party suppliers in our Scottish home area. Wholesale gas turnover increased as a result of both higher prices and volume growth, and was mainly due to increased balancing activities.

Overall, the UK Division s total customer numbers increased from 4.25 million to 5.11 million as a result of strong domestic growth in both gas and out-of-area electricity. Customer retention in our domestic home areas also improved to 61% at March 2005, in line with the industry average, with retention in our Scottish home area up 2 percentage points at 66% and retention in our Manweb area in line with last year.

Operating profit improved by £79 million for the year to £176 million and, excluding goodwill amortisation, was also higher by £79 million at £180 million*. Electricity and gas margins improved by £198 million due to growth in customer numbers combined with our investment in generation, which delivered £137 million of this increase. The effective management of our generation resource portfolio, including the benefit of our rolling commodity procurement strategy, contributed the majority of the remaining £61 million of margin growth. The substantial increase in customer numbers contributed to higher customer capture, energy efficiency and customer service costs of £45 million. Other net costs increased by £74 million, primarily due to £33 million of operating expenses relating to Damhead Creek and Brighton and higher depreciation and debt provisioning movements.

As in previous years, the division utilised onerous contracts provisions relating to the existing Peterhead legacy electricity contract and Rye House onerous gas contract. During the year, the division also utilised new onerous contracts provisions, established as part of the fair value accounting for the acquisitions of Damhead Creek and Brighton.

In the UK Division net capital investment for the year was £546 million, of which £454 million (83%) was invested for growth. Growth investment included the £320 million acquisition of the 800 MW Damhead Creek combined cycle power plant in Kent and the £71 million investment to acquire the remaining 50% of the 400 MW Brighton combined cycle power plant. Other growth investment of £63 million related primarily to our windfarm developments, notably the largest consented UK onshore windfarm project at Black Law, near Forth in Lanarkshire. Development of the project continues, with completion of approximately 100 MW scheduled for autumn this year. Construction is also underway at the 30 MW windfarm at Beinn Tharsuinn in Easter Ross and the 16 MW windfarm at Coldham near Cambridge. The salt-cavern natural

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gas storage facility at Byley, Cheshire, has been given the final go-ahead and pre-construction work is progressing well.

Renewable development remains a key part of our business strategy and the division is the leading developer of wind generation in the UK with approximately 3,000 MW in its renewable development pipeline, in addition to 158 MW that are operational and 142 MW under construction.

PPM Energy

PPM Energy is our competitive business in the US. The rate of PPM Energy s expansion is determined by the availability of attractive market opportunities for growing its portfolio of assets, and also by public policy, on issues such as the extension of PTCs.

PPM Energy s key financial information is shown in Table 24 and resource information in Table 25.

Ø **Table 24**

PPM Energy (£m)

	2004/05	2003/04
External turnover	**502.1**	342.8
Operating profit	**58.1**	36.1
Goodwill amortisation	**0.5**	0.6
Operating profit excluding goodwill*	**58.6**	36.7

PPM Energy s turnover for the year improved by £159 million to £502 million, after a £20 million adverse impact of the weaker US dollar, net of hedging. Dollar turnover increased by $328 million (56%) in the year and was principally volume related. Energy management turnover improved by $207 million largely due to improved contribution from long-term contractual arrangements to supply electricity and gas. Wind generation turnover increased by $64 million primarily as a result of 831 MW of wind generation resources being available for a full year, while average generation available during the prior year was 542 MW. Contracted and owned gas storage turnover grew by $57 million from increased contractual capacity, and revenue improvement at Alberta Hub.

PPM Energy s operating profit improved by £22 million to £58 million and, excluding goodwill amortisation, also increased by £22 million to £59 million*. Dollar operating profit, excluding goodwill amortisation, increased by $35 million to $98 million*. PPM Energy s contribution to the group s profit before interest and tax, excluding goodwill amortisation and including results from joint ventures, was $99 million*. In addition, the group s tax charge was reduced by $12 million as a result of PPM Energy s PTCs.

Gas storage activities improved by $48 million in the year, with increased contracted storage capacity delivering $34 million of this growth and the owned facilities at Alberta and Katy adding $14 million. Wind generation profit improved by $10 million, primarily due to 2003/04 investment in new windfarms delivering substantial volume growth. Energy management activities improved by $7 million mainly as a result of increased contributions from long-term contractual arrangements to supply electricity and gas. Net operating costs required to support increased business activities and infrastructure were higher by $24 million and depreciation increased by $6 million.

PPM Energy s net capital investment for the year was £84 million, with £79 million (94%) of this invested for growth, primarily on new wind generation projects where build is ongoing. For 2005/06, PPM Energy has announced 574 MW of new windfarm investment, specifically: the 75 MW Klondike II windfarm in Oregon; the 100 MW Trimont windfarm in Minnesota; the 150 MW Elk River windfarm in Kansas; the 150 MW Shiloh windfarm in California; and 50% of the 198 MW joint venture Maple Ridge windfarm in upstate New York, which is being developed along with Zilkha Renewable Energy of Houston. Including these windfarms, PPM Energy will have a total wind portfolio of approximately 1,405 MW by the end of December 2005, well on target towards its goal of at least 2,300 MW on-line by 2010. Approximately 90% of PPM Energy s operational windfarm output is committed under long-term contract. In December 2004, PPM Energy acquired the northeastern US wind energy developer, AREC (now called PPM Atlantic Renewable) in order to expand on the east coast of the US. Maple Ridge represents the first project in the northeastern US associated with the PPM Atlantic Renewable

Ø **Table 25**

PPM Energy resources

	Total owned or controlled at March 2005	New projects scheduled for 2005/06

Wind generation			
Plant net capability	MW	831	
Klondike II, Trimont, Elk River & Shiloh	MW		475
Maple Ridge 50% joint venture	MW		99
Thermal generation			
Plant net capability	MW	806	
Total all generating facilities	**MW**	**1,637**	**574**
Gas storage			
Capacity under ownership	BCF	46	6
Capacity under contract	BCF	30	
Total gas storage capacity	**BCF**	**76**	**6**

** Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

acquisition and PPM Energy now has approximately 9,000 MW in its renewable development pipeline.

In May 2005, PPM Energy announced plans to expand the Waha gas storage development project, in west Texas, from 7.2 BCF to 9.5 BCF based on strong market demand and favourable geological results. It also announced the acquisition of the 4.5 BCF Grama Ridge gas storage facility in New Mexico, from ConocoPhillips, which continues PPM Energy s profitable investment in gas storage assets. Including Grama Ridge, PPM Energy now has 80.5 BCF of gas storage under its ownership or control. PPM Energy intends to expand the Grama Ridge site to 6.0 BCF by the end of December 2005.

Net Assets

Group net assets decreased by 15% in the year, from £4,752 million to £4,038 million, primarily due to the loss retained for the year, as a result of the exceptional goodwill impairment charge associated with PacifiCorp. The balance sheet hedging strategy offset the impact of exchange movements on translation of our US results and net assets.

Fixed assets decreased by £186 million to £10,622 million mainly as a result of lower intangible assets, partly offset by our capital investment programme. Intangible assets, reduced by £1,011 million mainly as a result of the £927 million impairment charge of goodwill associated with PacifiCorp. The other movements on intangible assets comprised: £117 million of goodwill amortisation and a £46 million translation impact of the weaker US dollar on PacifiCorp and PPM Energy goodwill, partly offset by a net movement of £80 million relating to the acquisition and subsequent amortisation during the year of in-the-money gas contracts associated with Damhead Creek and Brighton power station. Tangible assets increased by £846 million due to gross capital expenditure of £1,013 million and fixed assets acquired of £452 million; partly offset by depreciation charged to the profit and loss account of £458 million, disposals of £22 million and, exchange movements on the translation of US balances of £138 million. Investments reduced by £21 million mainly due to the transfer of the Brighton power station from a joint venture to a subsidiary and the disposal of other investments, partly offset by PPM Energy s investment in the Maple Ridge joint venture.

Current assets, excluding short-term bank and other deposits, increased by £325 million to £1,977 million as at 31 March 2005. This was primarily due to higher UK Division accrued income and trade debtors associated with the growth in customer numbers, tariff rises and increased energy balancing activities, and higher PPM Energy debtors relating to contractual gas storage activities. Although the weaker US dollar and net cash receipts of £232 million arising from the cancellation of cross-currency swaps and the maturity of net investment hedging derivatives reduced debtors, this was partly offset by the effect of the weaker US dollar on the valuation of the total portfolio of financial instruments associated with our balance sheet hedging strategy.

Creditors due within one year, excluding loans and other borrowings, were £452 million higher than last year, mainly due to higher corporation tax creditors as a result of fluctuations in the tax payable on foreign currency hedging gains, increased UK Division energy accruals, reflecting higher market prices and increased balancing activities, and higher contractual gas storage accruals in PPM Energy. This was partly offset by the effect of the weaker US dollar.

Provisions for liabilities and charges decreased by £14 million to £1,733 million as at 31 March 2005, with a £91 million increase in deferred tax more than offset by £105 million of other provisions movements. The other provisions movements comprised: provisions acquired of £87 million; an increase of £108 million in new provisions, mainly for pensions and other post-retirement benefits; and £19 million unwinding of discount. This was offset by: £279 million of provisions utilised in the year, the majority being pensions and other post-retirement benefits and onerous contracts; an environmental provision release of £31 million; and a £9 million reduction due to the weaker US dollar.

Deferred income, which principally represents grants and customer contributions in our US and UK regulated businesses, reduced by £8 million reflecting amounts receivable during the year of £51 million, net of £19 million released to the profit and loss account, £37 million, primarily relating to amounts to be refunded as part of the new BETTA trading arrangements and £3 million of foreign exchange movements.

Total Recognised Gains and Losses

The Statement of Total Recognised Gains and Losses combines the profit or loss for the year together with other gains and losses taken directly to reserves as required under UK GAAP. Total recognised losses for the year to 31 March 2005 were £302 million compared to £522 million of recognised gains for the prior year. This decrease of £824 million was as a result of the £927 million exceptional goodwill impairment charge, partly offset by £81 million growth in underlying profit for the financial year; a £16 million favourable year-on-year movement in the net impact of foreign exchange movements and hedging of the group s results and net assets; and a £6 million revaluation reserve arising on the purchase of the remaining 50% of the Brighton power station. The weaker dollar exchange rates during the year resulted in unfavourable exchange movements of £100 million, which were offset by the benefits arising from our financial strategy to hedge foreign currency net assets of £146 million less tax associated with specific hedging activities of £46 million.

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Significant Changes

Any significant developments and post-balance sheet events that have occurred since 31 March 2005 have been noted in this Annual Report & Accounts and the report on Form 20-F, expected to be filed with the SEC in June 2005. Otherwise, there have been no significant changes since 31 March 2005.

5 Overview of the Year to March 2004

Group turnover for the year to 31 March 2004 was £5,797 million, an increase of £523 million on 2002/03, with the majority of the increase in the UK Division from balancing our electricity and gas positions, which was offset in cost of sales. The weaker US dollar reduced sterling revenues by £204 million. The translation effect of foreign exchange on earnings was mitigated by our hedging strategy.
PacifiCorp s turnover for 2003/04 was down by £181 million at £2,319 million mainly as a result of a £179 million adverse translation impact of the weaker US dollar. Dollar turnover in PacifiCorp was in line with 2002/03 as higher retail revenues from greater customer usage, favourable weather conditions and higher prices, were offset by lower wholesale volumes. Infrastructure Division s turnover grew by £44 million to £358 million due to increased regulated income from higher sales to third party electricity suppliers and from increased new connection activities. The UK Division experienced turnover growth of 29%, with revenues rising by £630 million to £2,777 million mainly as a result of balancing activities in England & Wales and improved retail and wholesale gas revenues. PPM Energy s turnover improved by £57 million to £343 million, after a £25 million adverse US dollar translation impact, as a result of increased sales of natural gas, activities around storage assets, the addition of new wind generation and gas storage expansion.

There was no turnover from discontinued operations during 2003/04, while the 2002/03 results included turnover of £27 million generated in the period prior to the disposal of Southern Water, which was completed on 23 April 2002.

Cost of sales of £3,631 million increased by £404 million, reflecting substantial growth in balancing our electricity and gas positions within the UK Division, offset in part by lower wholesale purchases in PacifiCorp and by the favourable US dollar translation impact.
Transmission and distribution costs increased by £32 million to £545 million as a result of higher UK Division customer service support and credit management costs reflecting growth in customer numbers, and storm damage costs, higher depreciation and labour-related costs in PacifiCorp, partly offset by the favourable US dollar translation impact.

administrative expenses increased by £23 million* due to increased energy efficiency and customer capture costs in the UK Division as a result of customer growth and increased costs in PPM Energy to support business growth, partly offset by the favourable US dollar impact. **Depreciation** for continuing operations, which is included within each of the three preceding cost categories, was broadly in line with 2002/03 at £439 million. Increased levels of capital investment throughout the group resulted in higher depreciation charges, particularly in the US, however, the impact of the weaker dollar on translation more than offset this.

Ø Table 26

Administrative expenses (£m)

	2003/04	2002/03
Administrative expenses	**626.2**	614.5
Goodwill amortisation	**(128.0)**	(139.0)
Administrative expenses excluding goodwill*	**498.2**	475.5

As shown in Table 27 **group operating profit** improved significantly, up £77 million (8%) to £1,023 million and, excluding goodwill amortisation, increased by £66 million to £1,151 million* for the year to 31 March 2004. Each of our four businesses delivered improved operating profit in 2003/04. In particular, our competitive businesses, UK Division and PPM Energy, produced strong performances with combined operating profit, excluding goodwill amortisation, up by over 29%* compared to 2002/03.

In PacifiCorp operating profit, excluding goodwill amortisation, increased by £23 million to £619 million*, benefiting from strong retail revenue growth and the delivery of further operational cost efficiencies, partly offset by the impact of the weaker US dollar. Infrastructure Division s operating profit showed an increase of £26 million (7%) to £394 million, primarily from higher regulated revenues and lower net operating costs. The UK Division s operating profit, excluding goodwill amortisation, improved by £23 million to £101 million* due to a combination of customer growth and prices resulting in improved electricity margins. In PPM Energy, the benefit of our organic investment helped operating profit, excluding goodwill amortisation, grow by £8 million to £37 million*.

Ø Table 27

Group operating profit (£m)

	2003/04	2002/03
Operating profit	**1,022.6**	945.9
Goodwill amortisation	**128.0**	139.0
Operating profit excluding goodwill*	**1,150.6**	1,084.9

Administrative expenses (including goodwill amortisation) as shown in Table 26 were £12 million higher than 2002/03 at £626 million. Excluding goodwill amortisation,

Operating profit in 2002/03 included £14 million from discontinued operations.

Goodwill amortisation of £128 million was £11 million lower than 2002/03 mainly as a result of the translation impact

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of the weaker US dollar reducing the goodwill charge for PacifiCorp.

The **net interest** charge for 2003/04 reduced by £16 million to £238 million, mainly due to favourable exchange benefits from the weaker US dollar of £17 million, and also from lower interest rates in both the UK and US. The benefit to interest from our dollar balance sheet hedging strategy, whereby the group swaps out of sterling liabilities into dollar liabilities in order to hedge its US dollar denominated net assets, was £39 million, £7 million lower than 2002/03 due to changes in the UK/US interest rate differential.

As shown in Table 28, **profit before tax** grew substantially by £95 million (14%) to £792 million. Excluding goodwill amortisation, profit before tax improved by £84 million to £920 million* with continuing operations delivering £95 million of the increase, offset in part by the contribution to 2002/03 profit before tax from discontinued operations of£ 11 million. The average US dollar to pound sterling exchange rate for 2003/04 for US profit before tax, excluding goodwill amortisation, and before the benefits of our hedging strategy, was $1.69. We sold forward our forecast dollar earnings at an average rate of $1.41 and this delivered an earnings hedging benefit compared to the average rate for 2003/04 of approximately £60 million. This, therefore, protected group profit from the effect of the weaker US dollar, ensuring results were in line with our expectations.

Ø **Table 28**

Profit before tax (£m)

	Continuing operations and Total 2003/04	Continuing operations 2002/03	Discontinued operations 2002/03	Total 2002/03
Profit before tax	**792.1**	685.8	11.0	696.8
Goodwill amortisation	**128.0**	139.0		139.0
Profit before tax excluding goodwill*	**920.1**	824.8	11.0	835.8

The **tax charge** for 2003/04 increased by £39 million to £248 million, as a result of higher pre-tax profit and a higher effective rate of tax, which was 31% for 2003/04 compared to 30% for 2002/03. Excluding goodwill amortisation, the effective rate of tax was 27%* compared to 25%* for 2002/03. he effective rate of tax was impacted by the geographical mix of profit because of the higher rates applied to taxable profits in the US (around 38%) compared to the UK (30%). The effective rate was lower than the statutory rate because the group sought to carry out its commercial activities in a tax efficient manner and benefited from the group s financing arrangements.

Profit after tax, as shown in Table 29, improved by £56 million to £544 million. Excluding goodwill amortisation, profit after tax grew by £45 million (7%) to £672 million*, with our strong operating results and lower interest charges, being offset by higher tax charges.

Ø **Table 29**

Profit after tax (£m)

	2003/04	2002/03
Profit after tax	**543.7**	487.8
Goodwill amortisation	**128.0**	139.0
Profit after tax excluding goodwill*	**671.7**	626.8

As a result of improved performance, **earnings per share**, as shown in Table 30, increased by 3.23 pence to 29.40 pence (12%). Excluding goodwill amortisation, earnings per share increased by 2.69 pence (8%) to 36.40 pence* with the improvement comprising 3.10 pence from continuing operations, partly offset by 0.41 pence from discontinued operations reported in 2002/03.

Ø **Table 30**

Earnings per share (pence)

	Continuing operations and Total 2003/04	Continuing operations 2002/03	Discontinued operations 2002/03	Total 2002/03
Earnings per share (EPS)	**29.40**	25.76	0.41	26.17
EPS impact of goodwill amortisation*	**7.00**	7.54		7.54
EPS excluding goodwill*	**36.40**	33.30	0.41	33.71

The 2003/04 full year **dividends** were 20.50 pence per share and were covered 1.43 times by earnings per share of 29.40 pence. Excluding goodwill amortisation, dividend cover was 1.78 times*.

Business Reviews

PacifiCorp

The key financial information is shown in Table 31.

Turnover in PacifiCorp reduced by £181 million to £2,319 million in the year to 31 March 2004, mainly because of the £179 million translation impact of the weaker US dollar. Dollar turnover was $4 million lower at $3,813 million. Residential, commercial and industrial revenue grew by $136 million (6%), with volumes 4% higher. Residential and commercial revenues increased by $80 million (9%) and $30 million (4%) respectively, mainly as a result of higher customer usage, including the impact of a warmer summer and colder winter, favourable prices from rate case revenues and growth in average customer numbers up by 28,000 (2%) in total. Industrial revenues increased by $26 million, or 4%, primarily due to favourable price mix, resulting from different customer tariffs in the various states PacifiCorp serves, with average customer numbers remaining constant. Wholesale revenues fell by $90 million, mainly due to lower long-and short-term sales volumes, partly offset by higher wholesale electricity prices. Movements in wholesale revenues are largely offset by similar changes in cost of sales, resulting from the balancing of power

** Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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positions. Other revenues fell by $50 million primarily due to the lower recovery of deferred power costs of $23 million.

Operating profit increased by £34 million to £497 million and, excluding goodwill amortisation, by £23 million ($65 million) to £619 million* ($943 million*). The unfavourable impact of the weaker dollar on operating profit was £21 million, net of hedging benefits from the forward sale of dollars. PacifiCorp s operating profit continued to benefit from strong retail revenue growth, with increased customer usage and new customers contributing $70 million, favourable weather conditions contributing $35 million, sales mix adding $11 million and higher prices from regulatory recoveries coming through from Oregon, California and Wyoming adding $18 million. These revenue upsides were partly offset by higher net power costs and other gross margin movements of $42 million reflecting the cost impact of higher retail loads, partly offset by a reduction in balancing volumes and the increased use of our own thermal generation at favourable prices. Other net costs increased by $36 million primarily as a result of pension and healthcare costs, maintenance charges, and costs of $10 million associated with the severe winter storms experienced in late December 2003 and early January 2004, partly offset by lower management costs. These increases were more than offset by PacifiCorp s ongoing cost efficiency programme, which delivered $49 million of benefits in the year. Depreciation was higher by $40 million reflecting increased levels of capital investment throughout the business.

Ø Table 31

PacifiCorp (£m)

	2003/04	2002/03
External turnover	**2,318.6**	2,499.4
Operating profit	**496.8**	462.8
Goodwill amortisation	**122.5**	133.9
Operating profit excluding goodwill*	**619.3**	596.7

Infrastructure Division

The key financial information is shown in Table 32.

Infrastructure Division s external turnover improved by £44 million to £358 million for the year to 31 March 2004. External electricity revenues increased by £23 million as a result of higher prices improving transmission turnover and higher volumes improving distribution turnover. Other revenues grew by £21 million and included higher income arising from our new connections business of £27 million, offset by a reduction in other rechargeable work.

were favourable by £6 million, primarily due to a change in the mix of capital and revenue activities undertaken and lower management costs. Property sale gains added a further £4 million to the operating profit improvement.

Ø Table 32

Infrastructure Division (£m)

	2003/04	2002/03
External turnover	**358.3**	314.0
Operating profit	**393.6**	367.8

UK Division

The key financial information is shown in Table 33.

Turnover within the UK Division increased by £630 million to £2,777 million for the year to 31 March 2004, with wholesale electricity activities contributing £380 million of the increase, retail and wholesale gas revenues contributing £193 million and higher retail electricity sales contributing £57 million.

Wholesale electricity sales in England & Wales, including exports, increased by £296 million, as prices recovered and volumes increased by 13,737 GWh to 25,577 GWh. Other core wholesale revenues increased by £84 million from higher volume and priced agency sales and other activities, including the waste-derived-fuel plant at Daldowie, which had been in operation for a full year. Gas turnover increased by £193 million reflecting growth in wholesale volumes of 32%, mainly due to increased balancing activities and also due to growth in domestic gas customers of 32% and favourable wholesale and retail prices. Retail electricity sales improved by £57 million, with out-of-area revenues up by £62 million primarily as a result of growth in domestic customers, offset in part by loss of market share in our home areas due to competition. Total customer numbers increased from 3.65 million to 4.25 million, with strong growth in domestic gas and out-of-area domestic electricity, being partly offset by loss of domestic electricity customers in our home Manweb area. Customer retention in our Scottish home area of 64% was in line with 2002/03 but the loss of customers in our Manweb area resulted in overall retention of home area residential customers falling by one percentage point to 60% for 2003/04, which was in line with the industry average.

The UK Division s operating profit improved by £23 million to £96 million for the year to 31 March 2004 and, excluding goodwill amortisation, increased by £23 million to £101 million*. Improved margins across the business s integrated value chain and continuing growth in customer numbers resulted in a £37 million increase in electricity margins. Gas margins improved by £2 million in the year due to favourable gas storage activities, which offset lower retail margins due to higher gas and transportation costs. Investment in energy efficiency and increased customer capture activities required to support customer growth increased by £27 million, but were offset in part by a £14 million reduction in other net costs due to lower management costs. The contribution from other

Infrastructure Division reported operating profit of £394 million, an increase of £26 million on 2002/03. Net regulated transmission and distribution use of system revenues increased by £13 million due to higher prices and volumes, and increased England-Scotland interconnector volumes contributed an additional £3 million to operating profit. Net operating costs

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business activities reduced by £3 million, mainly due to the loss of a contract in our metering operations.

Ø Table 33

UK Division (£m)

	2003/04	2002/03
External turnover	**2,777.4**	2,147.8
Operating profit	**96.1**	73.0
Goodwill amortisation	**4.9**	4.9
Operating profit excluding goodwill*	**101.0**	77.9

PPM Energy

The key financial information is shown in Table 34.

PPM Energy s turnover for the year to 31 March 2004 improved by £57 million to £343 million, after a £25 million adverse US dollar translation impact. Dollar turnover improved by $ 144 million (33%) in the year and was principally volume related and reflected increased sales of natural gas from fuel supply arrangements and optimization activities around gas storage assets and contracts, and new wind generation and gas storage expansion. Energy management turnover improved by $ 70 million with increased sales under fuel supply arrangements at the Klamath facility being partly offset by reduced counterparty demand for electricity output. New wind generation increased by $ 54 million primarily due to expanded output and turnover from new resources coming on-line during 2003/04. Gas storage turnover improved by $ 20 million, benefiting from the first full year of contribution from our Katy facility, acquired in December 2002, and increased ownership at the Alberta Hub.

PPM Energy s operating profit for the year to 31 March 2004 improved by £8 million to £36 million and, excluding goodwill amortisation, increased by £8 million ($18 million) to £37 million* ($63 million*) after a £2 million unfavourable translation effect of the weaker dollar. The contribution from the Katy and Alberta Hub gas storage facilities increased by $ 22 million, year on year. Returns from new wind generation and other projects improved operating profit by $ 15 million and energy management activities from optimising storage asset capacities and natural gas sales added a further $ 6 million. Operating costs and depreciation, which underpinned the business s growth, increased by $ 25 million.

Ø Table 34

PPM Energy (£m)

	2003/04	2002/03
External turnover	**342.8**	285.9
Operating profit	**36.1**	28.3

2004. In the financial year 2002/03, discontinued operations consisted of Southern Water. The disposal of Southern Water was completed on 23 April 2002 and turnover and operating profit generated in the period prior to disposal were £27 million and £14 million, respectively.

Total Recognised Gains and Losses

Total recognised gains for the year to 31 March 2004 were £522 million compared to gains for 2002/03 of £424 million. The increase was as a result of the £55 million growth in profit and a £42 million favourable year-on-year movement in the net impact of foreign exchange movements and hedging of the group s results and net assets. The weaker dollar exchange rates during 2003/04 resulted in unfavourable exchange movements of £538 million, which were largely offset by the benefits arising from our financial strategy to hedge foreign currency net assets of £475 million and favourable associated tax of £46 million, which included a credit of £48 million arising from the application of the transitional rules contained in the Finance Act 2002.

6 Research and Development

ScottishPower supports research into development of the generation, transmission, distribution and supply of electricity. It also continues to contribute, on an industry-wide basis, towards the cost of research into electricity utilisation and distribution developments. In financial years 2004/05, 2003/04 and 2002/03, research and development expenditure charged to the group s operating profit was £0.2 million, £0.2 million and £0.7 million, respectively.

7 Liquidity and Capital Resources

The treasury focus during the year continued to be to minimise interest costs and effectively manage both foreign exchange and interest rate risk. The group continues to ensure that borrowings are financed from a variety of competitive sources and that committed facilities are available both to cover uncommitted borrowings and to meet the financing needs of the group in the future. A further priority was to maximise the return on investment of the group s cash balances whilst avoiding excessive credit risk.

Goodwill amortisation	**0.6**	0.2
Operating profit excluding goodwill*	**36.7**	28.5

Discontinued Operations

There were no discontinued operations in the year to 31 March

Interest

As shown in Table 35, the net interest charge for the year to 31 March 2005 of £188 million was £50 million lower than the charge for the previous year, despite an increase in net debt. This reduction was mainly attributable to an £88 million benefit associated with our dollar balance sheet hedging

* *Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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strategy (2003/04: £39 million), favourable exchange benefits from the weaker US dollar of £14 million and lower effective interest rates in the US. The dollar balance sheet hedging strategy involves the group swapping out of sterling liabilities into dollar liabilities in order to hedge its US dollar denominated net assets. This also gives rise to the group paying interest in dollars and receiving interest in sterling, thereby benefiting as US interest rates were below those in the UK. Excluding the benefit of our dollar hedging strategy, underlying UK interest was £125 million, an increase of £18 million on last year, mainly reflecting increased interest on floating rate debt. In the US the interest charge reduced by £19 million to £151 million, principally as a result of favourable exchange rates. Interest (excluding a foreign exchange gain of £2 million) is covered by profit on ordinary activities before interest, excluding goodwill amortisation and the exceptional item, shown in Table 36, 6.3 times* for the year to 31 March 2005, improved from 4.9 times* for the previous year. Interest is covered by profit on ordinary activities before interest 0.8 times, compared to 4.3 times in the previous year.

In accordance with the group s interest policy, the group is targeting a long-term benchmark of at least 70% fixed rate interest. As at 31 March 2005, 98% of the group s net borrowings were fixed for periods of more than one year. Further discussion on interest rate policy is included within Risk Factors on page 79.

Ø **Table 35**

Interest (£m)

	2004/05	2003/04
Interest	**187.9**	238.1
Foreign exchange gain	**2.1**	
Interest excluding foreign exchange gain	**190.0**	238.1

Ø **Table 36**

Profit before interest (£m)

	2004/05	2003/04
Profit before interest	**158.6**	1,030.2
Goodwill amortisation	**117.5**	128.0
Exceptional item	**927.0**	
Profit before interest excluding goodwill and exceptional*	**1,203.1**	1,158.2

Balance Sheet Hedging

assets, the group s portfolio of cross-currency swaps will be adjusted accordingly.

Cash Flow and Net Debt

Table 37 provides a reconciliation of earnings before interest, tax, depreciation and amortisation (EBITDA) to cash inflow from operating activities, and, as such, effectively demonstrates how the group has converted operating profit into cash. During the year, £1.3 billion of the EBITDA of £1.7 billion, excluding the exceptional item, was converted into cash, with the remaining £0.4 billion being either invested in working capital to support growth of our competitive businesses, or being attributable to provision movements, mainly relating to the utilisation of onerous contracts within the UK Division. Group working capital requirements increased, primarily within the UK Division as a result of the significant growth in customer numbers and higher tariffs. Net cash provided by operating activities is impacted by seasonal movements in working capital throughout the year.

Ø Table 37

Reconciliation of EBITDA and EBITDA excluding the exceptional item to cash inflow from operating activities (£m)

	2004/05	2003/04
Operating profit	**152.6**	1,022.6
Share of operating profit in joint ventures & associates	**6.0**	7.6
Depreciation & amortisation	**600.1**	566.7
EBITDA	**758.7**	1,596.9
Exceptional item	**927.0**	
EBITDA excluding exceptional	**1,685.7**	1,596.9
Share of operating profit in joint ventures & associates	**(6.0)**	(7.6)
Other non-cash movements[1]	**(12.7)**	(15.0)
Movement in provisions for liabilities & charges	**(202.1)**	(87.6)
Working capital[2]	**(205.2)**	(122.7)
Cash inflow from operating activities	**1,259.7**	1,364.0

[1] Profit/loss on sale of tangible fixed assets; amortisation of share scheme costs; release of deferred income

[2] Increase/decrease in stock, debtors & creditors

As at 31 March 2005, the group had balance sheet hedges of $6.2 billion (March 2004: $5.9 billion). In addition to the $1.5 billion bonds issued during the current year and the $700 million convertible bonds issued in the prior year, liabilities have been created for periods out to March 2012, by means of cross-currency swaps totalling $4 billion. Maturing swaps have been renewed and new swaps put in place with maturities of 2007 and 2008. Following the write down of PacifiCorp s net

Net cash interest costs were £116 million compared with a profit and loss account charge of £188 million reflecting timing differences on the settlement of interest costs, the unwinding of discount on provisions, benefits associated with our hedging strategy and capitalised interest. Cash taxation was £99 million compared with a profit and loss account charge of £274 million. This mainly reflects cash tax timing differences arising from the group s investment programme, the settlement of outstanding items with the tax authorities and the cash tax benefit of the transitional rules of the Finance Act 2002, reported in the Statement of Total Recognised Gains and Losses in the prior year. Net cash receipts arising from the

** Non-GAAP performance measure and Non-GAAP liquidity measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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cancellation of cross-currency swaps were £92 million and proceeds from the maturity of net investment hedging derivatives were £140 million. The cancellation of cross-currency swaps was as a result of the $1.5 billion bonds issue during March 2005. Net proceeds arising from the issue of new debt and repayment of existing borrowings were £753 million and principally represented the issue of the new bonds.

In total, the above net cash inflows were sufficient to fund the group s capital expenditure and financial investment of £888 million and dividend payments of £386 million, as well as fund the group s acquisitions during the year. The cash outflow of £186 million associated with the management of liquid resources represented the transfer of cash into highly liquid non-demand deposits, such as bonds.

Net debt at 31 March 2005 was £4,147 million, £423 million higher than at 31 March 2004, with the translation impact of the weaker dollar and other non-cash movements reducing net debt by a net £46 million. Included in net debt are short-term bank and other deposits (including the liquid resources referred to above) of £1,748 million, up £400 million on the prior year. This was principally as a result of the cash proceeds from the cancellation of cross-currency swaps, the maturity of net investment hedging derivatives and the new bonds issue, effectively offsetting cash used to fund investment activities during the year, including the acquisition of Damhead Creek and the repayment of the £116 million debt acquired with the Brighton power plant. Total debt balances increased from £5,072 million to £5,895 million mainly due to the increase in debt associated with the $1.5 billion bonds issue, net of the translation impact and other non-cash changes of £48 million.

In addition to the cash generated from operations and existing cash balances, the group relies on flexible borrowing facilities from the capital markets, which are described in the Financing section below, at favourable rates of interest as a source of liquidity to fund investment as required. Issues of debt are influenced by levels of short-term debt, cash from operations, capital expenditure, market conditions, regulatory approvals and other considerations.

Management and external credit rating agencies utilise a number of financial ratios when assessing the performance of our business, and our financing arrangements are also subject to a number of ratio-based covenants contained within our principal credit agreements. Two of the main ratios monitored by ScottishPower management are gearing (net debt/equity shareholders funds) which increased to 104% from 79% at 31 March 2004 and the ratio of net debt to EBITDA, which is a measure used in banking covenants. The banking covenants allow for the exclusion of goodwill amortisation and the exceptional item. EBITDA is shown in Table 38 and net debt to EBITDA, excluding the exceptional item, was marginally higher at 2.5 times compared to 2.3 times last year, reflecting the increased net debt position.

Ø **Table 38**

EBITDA (£m)

	2004/05	2003/04
Profit before interest & tax	**158.6**	1,030.2
Depreciation & amortisation	**600.1**	566.7
EBITDA	**758.7**	1,596.9
Exceptional item	**927.0**	
EBITDA excluding exceptional	**1,685.7**	1,596.9
Cash inflow from operating activities	**1,259.7**	1,364.0

ScottishPower is committed to maintaining an A category credit rating for its principal operating subsidiaries, thereby allowing access to flexible borrowing sources at favourable cost. To achieve this rating, on completion of the sale of PacifiCorp, the group will target credit ratios of adjusted FFO/net debt of greater than 25% and FFO/interest cover of more than five times. ScottishPower will work closely with the rating agencies in order to ensure its rating objectives are achieved.

Financing

The group s external borrowings have generally been sourced in two separate pools. In the UK, Scottish Power UK plc (SPUK) has been the finance vehicle for the majority of the UK activities, although in future Scottish Power plc (SP plc) is likely to be the main borrower. In the US, predominantly all of the debt is issued by PacifiCorp, the regulated utility, and is entirely denominated in US dollars. Pursuant to the stock purchase agreement for the sale of PacifiCorp, there may be certain limitations on PacifiCorp s future borrowings.

In both the UK and the US, regulatory constraints apply to financing activities. SP plc is not permitted to borrow from its subsidiaries with the exception of certain intermediate holding companies in the US ownership chain and is currently financed by way of dividends, interest and external debt. During the year, SP plc renewed its $375 million 364-day facility to bring the maturity date in line with that of the $625 million facility maturing in June 2008. The two facilities represent varying commitments from a number of relationship banks. Both were undrawn at the year end. SP plc s revolving credit facilities contain financial covenants relating to interest cover (operating profit to net interest payable not less than 2.5 to 1), dividend cover (earnings to consolidated dividends not less than 1.25 to 1) and the ratio of net debt to EBITDA (not greater than 4.0 to 1). The company has been in compliance with these covenants throughout the year to 31 March 2005.

In March 2005 SP plc established a $4 billion US shelf registration for the issuance of debt and other securities. An inaugural issue of $1,500 million of bonds was made in March 2005. The bonds were split into three maturities: $550 million due 2010, $600 million due 2015 and $350 million due 2025, with coupons of 4.910%, 5.375% and 5.810%, respectively. In conjunction with the issue of the bonds, cross-currency swaps totalling $1,500 million were cancelled generating a cash

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receipt of £92 million. The bonds replace these swaps as a hedge of the US net assets. There have been no new issues in the year under ScottishPower s euro-medium-term note programme, established in November 1997. Cumulative issues outstanding under the programme total some $2,460 million against a programme limit of $7,000 million. SP plc and SPUK are the issuers under the programme.

During the year SPUK has not added to its index-linked liabilities, currently totalling £275 million. Total borrowings from the European Investment Bank (EIB) amounted to £199 million. The EIB debt within SP Manweb plc contains financial covenants relating to interest cover (EBITDA to net interest payable not less than 4.0 to 1) and net debt to EBITDA (not greater than 4.0 to 1) of SP Manweb plc. SP Manweb plc has been in compliance with these covenants throughout the year to 31 March 2005.

The UK distribution, transmission and generation subsidiaries have provided upstream guarantees to support the majority of SPUK s debt that existed at 1 October 2001, following their incorporation to comply with the Utilities Act 2000. As at 31 March 2005, the total amount of debt guaranteed by the three companies amounted to £2,089 million. New debt issued by SPUK after 1 October 2001 is not permitted to benefit from the guarantee of SPUK s subsidiaries, SP Distribution Limited and SP Transmission Limited.

During the year, PacifiCorp issued new long-term debt in the form of two series of first mortgage bonds of $200 million each, with maturities of August 2014 and August 2034 and coupons of 4.95% and 5.90%, respectively. In addition, scheduled repayments of $260 million were made during the year. At 31 March 2005, PacifiCorp had $250 million available under a currently effective shelf registration. Securities that may be issued under this registration include first mortgage bonds, unsecured debt securities and no par serial preferred stock. PacifiCorp plans to file a shelf registration statement with the SEC during the coming year covering $750 million of first mortgage bonds and unsecured debt. During May 2005, PacifiCorp received authority to issue up to an additional $1,000 million of long-term debt from the Oregon Public Utility Commission and the Idaho Public Utilities Commission and up to $400 million of PacifiCorp s first mortgage bonds from the Washington Utilities and Transportation Commission. Prior issuances had fully utilised previous state commission authorisations. Any such issuance would be subject to market conditions. PacifiCorp has debt maturities out as far as 2034/35.

In May 2004, PacifiCorp replaced its expiring $500 million and $300 million facilities with a new $800 million facility having a maturity of May 2007. This new bank facility is provided by core relationship banks, the majority of which are common to both the US and UK bank facilities. PacifiCorp s principal debt limitations are a 60% debt to defined capitalisation test and an interest coverage covenant (EBITDA to interest of 2.0 to 1), contained in its principal credit agreements. PacifiCorp has been in compliance with these covenants throughout the year to 31 March 2005. In addition, under the Public Utility Holding Company Act of 1935 there are restrictions on the ability of group companies to lend to or borrow from one another.

Credit Ratings

SP plc, SPUK and PacifiCorp have credit ratings published by some or all of Standard & Poor s Ratings Group (S&P), Moody s Investors Service (Moody s) and The Fitch Group (Fitch) as shown in Table 39. During the year both S&P and Moody s removed their negative outlook on the ratings and have changed the outlook to stable. These security ratings are not recommendations to buy, sell or hold securities. The ratings are subject to change or withdrawal at any time by the respective credit rating agencies. Each credit rating should be evaluated independently of any other rating.

Ø Table 39
Credit ratings

	S&P	Moody s	Fitch
SP plc	BBB+	Baa1	BBB+
SPUK (long-term)	A-	A3	A
PacifiCorp (senior secured)	A-	A3	A
PacifiCorp (unsecured)	BBB+	Baa1	A-
SPUK and PacifiCorp (short-term)	A-2	P-2	F-2

Any adverse change to credit ratings of group companies could negatively impact on their ability to access capital markets and on the rates of interest that they would be charged for such access. The EIB debt within SP Transmission Limited and SP Distribution Limited contains credit downgrade language, which does not constitute default, but means that, should the ratings of SP Transmission Limited or SP Distribution Limited fall, the EIB will be entitled to ask for additional security in the form of a guarantee acceptable to the EIB. PacifiCorp has no rating downgrade triggers within its debt instruments, although interest rates on loans under its bank facilities and commitment fees on the facilities would increase with a ratings downgrade, as would the interest rates and commitment fees on SP plc s facilities.

The investment of surplus cash is undertaken to maximise the return within Board approved policies, which govern the ratings criteria, maximum investment and the maturity with any one counterparty. Counterparties are required to have a short-term rating of at least A-1, P-1 or F-1 from one of the three major rating agencies.

Contractual Obligations and Commercial Commitments

The group enters into various financial obligations and commitments in the normal course of business. Contractual financial obligations are considered to comprise known future cash payments that the group is required to make under contractual arrangements in place at 31 March 2005. Commercial commitments are defined as those obligations of the group, which only become payable if certain pre-defined events occur.

Table 40 details the group s contractual obligations at 31 March 2005.

Ø **Table 40**

Contractual obligations at 31 March 2005 (£m)

	Payments due by period				
	Less than 1 year	1-3 years	3-5 years	More than 5 years	**Total**
Loans and other borrowings (including overdrafts)	729.5	695.1	2,041.9	4,978.5	**8,445.0**
Finance leases	1.7	3.7	3.9	22.7	**32.0**
Operating leases	13.6	20.0	13.9	93.2	**140.7**
PacifiCorp preferred stock	2.0	25.8			**27.8**
Energy purchase commitments	3,002.4	2,478.0	1,258.1	3,103.0	**9,841.5**
Capital commitments	385.0	51.3	3.4	4.4	**444.1**
Other firm commitments	89.2	111.7	39.0	375.1	**615.0**
Total	**4,223.4**	**3,385.6**	**3,360.2**	**8,576.9**	**19,546.1**

The loans and other borrowings figures in Table 40 are stated at book value at 31 March 2005 and include future interest payments under these obligations as well as interest commitments on the group s treasury-related derivatives.

Energy purchase commitments included within Table 40 arise principally from short-and long-term power and fuel purchase contracts. Further detailed information on power purchase commitments is set out in Note 30(c) to the Group Accounts on page 148.

Other firm commitments included within Table 40 arise principally from transportation, transmission and storage commitments and costs associated with hydroelectric licences, asset retirement obligations and information technology services.

In addition to the contractual obligations in the table above, the group expects to contribute £42.8 million to its UK pension schemes, £37.1 million ($70.1 million) to the PacifiCorp pension scheme and £15.8 million ($29.9 million) for other post-retirement benefits in the year ending 31 March 2006.

The group s commercial commitments include surety bonds that provide indemnities for PacifiCorp in relation to various commitments it

The group invested £1,377 million in its asset base during the year ended 31 March 2005. The group s estimated net investment in its asset base for the year ended 31 March 2006, which is subject to continuing review and revisions, is approximately £1.5 billion, based on a US dollar/UK sterling exchange rate of approximately $1.80, and represents investment in growth projects and refurbishment.

Going Concern

The directors confirm that the group remains a going concern on the basis of its future cash flow forecasts and has sufficient working capital for present requirements.

8 Fair Value of Derivative Contracts

The group uses derivative instruments in the normal course of business to offset fluctuations in earnings, cash flows and equity associated with movements in exchange rates, interest rates and commodity prices. In limited circumstances the group holds derivative financial instruments for energy management purposes. These derivatives are marked to market and unrealised gains and losses are recognised in the group s profit and loss account. The net unrealised gains on financial assets and liabilities held for trading at 31 March 2005 was £5.7 million. Table 41 details the changes in the fair value of the group s energy related and treasury derivative contracts which are subject to the requirements of Statement of Financial Accounting Standard (FAS) No. 133 Accounting for Derivative Instruments and Hedging Activities , as amended. FAS 133 requires, for the purposes of US GAAP, all derivatives, as defined by the standard, to be marked to market, except for those which qualify for specific exemption under the standard or associated guidance, for example those defined as normal purchases and normal sales. The derivatives which are marked to market in accordance with FAS 133 include only certain of the group s commercial contractual arrangements as many of these arrangements fall outside the scope of FAS 133. In addition, the effect of changes in the fair value of certain long-term contracts entered into to hedge PacifiCorp s future retail energy resource requirements, which are being marked to market in accordance with FAS 133, are subject to regulation in the US and are therefore deferred as regulatory assets or liabilities pursuant to FAS 71 Accounting for the Effects of Certain Types of Regulation . These amounts are expected to be recovered through rate cases. The FAS 133 liability relating to PacifiCorp of £81.7 million, as set out in Table 41, is offset under US GAAP by a US regulatory net asset of £89.9 million.

The forward price curves for energy commodity prices are derived using market price quotations when available and are developed internally using models when market quotations are unavailable. Market quotations are received from independent has to third parties for obligations in the event of default on behalf of PacifiCorp. The majority of these bonds are continuous in nature and renew annually. The estimated level of PacifiCorp s surety bonding beyond 31 March 2005 is approximately £13 million. This estimate is based on current information and actual amounts may vary due to rate changes or changes to the general operations of PacifiCorp.

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energy brokers and reporting services, as well as direct information received from third party offers and actual transactions entered into by the group, for certain actively traded locations covering the first three years (six years for the US). For the less actively traded locations and periods extending past three years (six years for the US), the forward price curves are developed internally using various models that are intended to simulate expected market price levels. Long-term prices generally are derived using a fundamentals model (cost-to-build approach) that is updated at least quarterly, to reflect changes in the market. Prices for less actively traded locations are developed based on historically observed price relationships with actively traded locations. Short-term energy contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward price curve. Energy contracts with explicit or embedded optionality and long-term energy contracts are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate market curve. The optionality is valued using a modified Black-Scholes model or a stochastic simulation (Monte Carlo) approach. Each option component is modelled and valued separately using the appropriate forward price curve.

Interest rate swaps and forward-rate agreements are valued by calculating the present value of future cash flows, estimated using forward market curves.

Interest rate swaptions are valued using the market yield curve and implied volatilities at the period end. Cross-currency swaps are valued by adding the present values of the two legs of each swap: present values are calculated by discounting the future cash flows, estimated using the appropriate forward price curve for that currency, at the appropriate market discount rates. Forward foreign exchange contracts are valued using market forward exchange rates at the period end.

The methodology applied in the fair value of derivative contracts under FAS 133, is consistent with that used for IAS 39. Further details are provided in Section 14 on page 64.

In Table 41 changes in fair values attributable to changes in valuation techniques and assumptions reflect changes in the fair value of mark-to-market values as a result of applying refinements in valuation modelling techniques.

Other changes in fair value reflect changes in underlying economic fundamentals which impact on the value of the derivative including commodity price risk, which is influenced by contract size, term, location and unique or specific contract terms; movements in foreign exchange rates which impact the value of cross-currency swaps; and movements in interest rates which impact on the value of interest rate swaps, forward-rate agreements and cross-currency swaps.

Ø Table 41

Fair value of energy-related and treasury

derivative contracts (£m)

	PacifiCorp	PPM Energy	UK Division	Treasury	**Total**
Fair value of contracts outstanding at 1 April 2004	(225.7)	124.4	69.2	376.3	**344.2**
Contracts realised or otherwise settled during the year	(21.1)	(20.1)	(32.7)	(212.7)	**(286.6)**
Changes in fair values attributable to changes in valuation techniques and assumptions					
Other changes in fair value	162.2	(18.7)	275.9	127.9	**547.3**
Foreign exchange movement	2.9	(2.5)			**0.4**
Fair value of contracts outstanding at 31 March 2005	**(81.7)**	**83.1**	**312.4**	**291.5**	**605.3**

As shown in Table 42, standardised derivative contracts that are valued using market quotations are classified as prices based on quoted market prices from third party sources. All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as prices based on models and other valuation methods.

Ø Table 42

Maturity profile of fair value of derivative

contracts outstanding (£m)

	Within 1 year	Between 1-3 years	Between 3-5 years	After 5 years	**Total**
Prices based on quoted market prices from third	(33.3)	(57.8)	6.4	(9.1)	**(93.8)**

party sources					
Prices based on models and other valuation methods	301.0	408.8	71.5	(82.2)	**699.1**
Total	**267.7**	**351.0**	**77.9**	**(91.3)**	**605.3**

9 Pension Arrangements

As required by the transitional arrangements for Financial Reporting Standard (FRS) 17 Retirement Benefits , we have disclosed, at 31 March 2005, a deficit of £147 million (2004: £120 million) net of deferred tax for our UK defined benefit pension schemes and a deficit of £181 million ($342 million) (2004: £180 million ($331 million)) net of deferred tax for our US schemes. With the obligation to fund other post-retirement benefits in the US, we have also reported a deficit under FRS 17 at 31 March 2005 of £83 million ($157 million) (2004: £96 million ($177 million)), net of deferred tax. Had the measurement rules within FRS 17 been applied during the financial year 2004/05, the group s operating profit would have increased by £14 million (2003/04: £24 million), finance costs would have decreased by £1 million (2003/04:

increased by £15 million) and profit before tax would have increased by £15 million (2003/04: £9 million). Net assets and reserves at 31 March 2005 would have been reduced by £341 million (2004: £311 million).

FRS 17 prescribes detailed rules for the calculation of pension scheme assets and liabilities and indicates the net accounting surplus or deficit that would exist on an ongoing basis using market conditions at the balance sheet date. Fluctuations in investment conditions can result in significant volatility in funding levels.

Pension schemes are, however, managed over the long-term. Investment and liability decisions are based on underlying actuarial and economic circumstance with the intention of making sure that the schemes have sufficient assets to meet liabilities as they fall due, rather than meeting accounting requirements. The company and the trustees of the group s schemes have reviewed the investment strategy for the asset/liability matching of the group s schemes and this has resulted in agreement to a gradual shift towards a higher element of bond/gilt holdings from equities.

The charge in the year for these pension schemes, as reflected in the group profit and loss account, is based on Statement of Standard Accounting Practice (SSAP) 24 Accounting for pension costs . The charge on this basis has increased from £28 million to £36 million in the UK, and decreased from £39 million ($71 million) to £38 million ($71 million) in the US. Achieving regulatory recovery of these costs is a priority and there is a focus on ensuring inclusion of any increased expense in US rate cases and this is already being achieved in recent US rate cases. In the UK, pension costs were included in the UK regulatory price review.

10 Creditor Payment Policy and Practice

In the UK, the group s current policy and practice concerning the payment of its trade creditors is to follow the Better Payment Practice Code to which it is a signatory. Copies of the Code may be obtained from the Department of Trade and Industry or from the website www.payontime.co.uk.

The group s policy and practice is to settle terms of payment when agreeing the terms of the transaction, to include the terms in contracts and to pay in accordance with its contractual and legal obligations. The group s creditor days at 31 March 2005 for its UK businesses and US businesses were 15 days and 42 days, respectively.

11 Critical Accounting Policies UK GAAP

The group s Accounts are prepared in accordance with UK GAAP. This requires the directors to adopt those accounting policies, which are most appropriate for the purpose of the Accounts giving a true and fair view. The group s material accounting policies are set out in full on pages 108 to 111. In preparing the Accounts in conformity with UK GAAP, the directors are required to make estimates and assumptions that impact on the reported amounts of revenues, expenses, assets and liabilities. Actual results may differ from these estimates. Certain of the group s accounting policies have been identified as critical accounting policies by considering which policies involve particularly complex or subjective decisions or assessments and these are discussed below. The discussion below should be read in conjunction with the full statement of Accounting Policies . The critical accounting policies have been discussed with the group s senior management and the Audit Committee.

UK GAAP Turnover

Prices for electricity supplied to the group s retail customers in the US are determined by the relevant regulatory authorities. In the group s UK Division, prices for electricity and gas supplied to retail customers are determined within competitive markets. In both cases, the assessment of energy sales to customers is based on meter readings, which are carried out on a systematic basis throughout the year. At the end of each accounting period, amounts of energy delivered to customers since the last billing date are estimated and the corresponding unbilled revenue is estimated and recorded as sales. Unbilled revenues included within the group s balance sheet relating to the group s retail customers at 31 March 2005 amount to £322 million (2004: £256 million).

UK GAAP Impairment of Goodwill

Goodwill on the group s acquisitions after 1 April 1998 has been capitalised and amortised over its estimated useful economic life. Where there is an indicator of impairment, goodwill is required to be reviewed for impairment. In November 2004, the Board began a strategic review of PacifiCorp as a result of its performance and the significant investment it required in the immediate future. In May 2005, the Board concluded that in light of the prospects for PacifiCorp, the scale and timing of the capital investment required and the likely profile of returns, shareholders interests were best served by a sale of PacifiCorp and the return of capital to shareholders. As a consequence, the group has undertaken a review of the carrying value of the goodwill allocated to the PacifiCorp reporting segment as at 31 March 2005. The estimated recoverable value has been based on net realisable value, with reference to the price of comparable businesses, recent market transactions and the estimated proceeds from disposal. This has resulted in an exceptional charge in the year ended 31 March 2005 for the impairment of

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goodwill of £927 million which is disclosed separately within operating profit as an exceptional item.

UK GAAP Environmental Provisions

Provision is made for liabilities relating to environmental obligations when the related environmental disturbance occurs, based on the net present value of estimated future costs. Estimates of environmental liabilities are principally based on reports prepared by external consultants. The ultimate cost of environmental disturbance is uncertain and there may be variances from these cost estimates, which could affect future results. At 31 March 2005, the group had provided £17.6 million (2004: £60.5 million) for environmental obligations.

UK GAAP Decommissioning and Mine Reclamation Provisions

Provision is made for the decommissioning of major capital assets where the costs are incurred at the end of the lives of the assets. Similarly, closure and reclamation costs are a normal consequence of mining with the majority of the expenditure incurred at the end of the life of the mine. Although the ultimate cost to be incurred is uncertain, estimates have been made of the respective costs based on local conditions and requirements. At 31 March 2005, the group had provided £91.8 million (2004: £84.3 million) for decommissioning costs and £74.6 million (2004: £79.6 million) for mine reclamation costs.

UK GAAP Tax

The group s tax charge is based on the profit for the year and tax rates in force at the balance sheet date. Estimation of the tax charge requires an assessment to be made of the potential tax treatment of certain items which will only be resolved once finally agreed with the relevant tax authorities. In particular, the tax returns of the group s US businesses are examined by the Internal Revenue Service and state agencies on a several year lag. Assessment of the likely outcome of the examinations is based upon historical experience and the current status of examination issues.

others. The evaluation of these contingencies is performed by various specialists inside and outside of the group. Accounting for contingencies requires significant judgement by management regarding the estimated probabilities and ranges of exposure to potential loss. The directors assessment of the group s exposure to contingencies could change as new developments occur or more information becomes available. The outcome of the contingencies could vary significantly and could materially impact the group s results and financial position. The directors have used their best judgement in applying FRS 12 to these matters.

UK GAAP Pensions and Other Post-Retirement Benefits

The group operates a number of defined benefit schemes for its employees. In addition, other post-retirement benefits are provided to employees within the group s US businesses. The group accounts for these arrangements under UK GAAP in accordance with SSAP 24. The impact on the group s Accounts had the measurement rules of FRS 17 been implemented is summarised in the Pension Arrangements section on page 58.

The expense and balance sheet items relating to the group s accounting for pension schemes under SSAP 24 are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, earnings increases and pension increases in payment. These actuarial assumptions are reviewed periodically and modified as appropriate. The effect of modifications is generally amortised over future periods. The assumptions adopted are based on prior experience, market conditions and the advice of plan actuaries.

The group chooses a discount rate for each scheme which reflects yields on high-quality fixed-income investments, which may be increased for SSAP 24 purposes to allow for higher returns expected over the longer-term from the schemes equity holdings. The pension liability and future pension expense both increase as the discount rate is reduced. If the SSAP 24 expense for the year ended 31 March 2005 had been based on a discount rate 0.5% p.a. higher or lower than those actually used, the expense would have reduced or increased, respectively, by £19 million in respect of the group s UK pension schemes and £5 million in respect of the group s US pension schemes.

The discount rates used for the purposes of UK GAAP for the group s principal pension schemes are set out in Table 43. Discount rates may vary between schemes as a result of different investment strategies, liability profiles and timing of the actuarial valuations.

Ø **Table 43**

Discount rates

	Discount rate UK GAAP (SSAP 24)	Discount rate US GAAP

Pension fund		
ScottishPower	6.0%	5.4%
Manweb	6.0%	5.4%
PacifiCorp	6.25%	5.75%

UK GAAP Provisions and Contingencies

In accounting for contingencies, the group applies FRS 12 Provisions, Contingent Liabilities and Contingent Assets . FRS 12 requires that a provision be recognised where there is a present obligation as a result of a past event, it is probable that a transfer of economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. If these conditions are not met, no provision should be recognised. However, contingent liabilities are required to be disclosed in the Notes to the Group Accounts, unless the possibility of a transfer of economic benefits is remote. Contingent gains are not recognised unless realisation of the profit is virtually certain.

Provisions are established when required based upon the directors best judgement. Appropriate disclosures are made regarding litigation, tax matters, environmental issues, among

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12 Critical Accounting Policies

US GAAP

In addition to preparing the group s Accounts in accordance with UK GAAP, the directors are also required to prepare a reconciliation of the group s profit or loss and shareholders funds between UK GAAP and US GAAP. The adjustments required to reconcile the group s profit or loss and shareholders funds from UK GAAP to US GAAP are explained in Note 34 to the Group Accounts. Certain of the group s US GAAP accounting policies have been identified as critical US GAAP accounting policies and these are discussed below. The discussion below should be read in conjunction with the full discussion of the differences between the group s UK and US GAAP accounting policies set out in Note 34.

US GAAP US Regulatory Assets

The group prepares its US GAAP financial information in accordance with FAS 71 in respect of its regulated US business, PacifiCorp.

In order to apply FAS 71, certain conditions must be satisfied, including the following: an independent regulator must set rates; the regulator must set the rates to cover the specific costs of delivering service; and the service territory must lack competitive pressures to reduce rates below the rates set by the regulator. FAS 71 requires the group to reflect the impact of regulatory decisions and requires that certain costs be deferred on the balance sheet under US GAAP until matching revenue can be recognised. FAS 71 provides that regulatory assets may be capitalised, under US GAAP, if it is probable that future revenues, in an amount at least equal to the capitalised costs, will result from the inclusion of that cost in allowable costs for ratemaking purposes. In addition the rate actions should permit recovery of the specific previously incurred costs, rather than to provide for expected levels of similar future costs. An entity applying FAS 71 does not need absolute assurance prior to capitalising a cost, only reasonable assurance. Based on the group s US regulatory net asset balance under US GAAP at 31 March 2005, if the group stopped applying FAS 71 to its remaining regulated US operations, it would have recorded a loss after tax, of £337 million under US GAAP in relation to this balance. PacifiCorp intends to seek recovery of all of its prudent costs, including stranded costs, in the event of deregulation. However, due to the current lack of definitive legislation, it is not possible to predict whether PacifiCorp will be successful.

Because of potential regulatory and/or legislative actions in the various states in which PacifiCorp operates, the group may have regulatory asset write-offs and charges for impairment of regulatory assets, under US GAAP, in future periods. Such impairment reviews would involve estimates of future cash flows including estimated future prices, cash costs of operations, sales and load growth forecasts and the nature of any legislative or regulatory cost recovery mechanism.

US GAAP Impairment of Goodwill

FAS 142 Goodwill and Other Intangible Assets deals with the accounting for goodwill and other intangible assets upon their acquisition and their subsequent measurement. The standard requires that goodwill is not amortised but is tested for impairment at least annually. Under FAS 142, the impairment test is in two stages. The first step is a screen for potential impairment. This compares an estimate of the fair value of the reporting unit that contains the goodwill with the carrying value of the net assets (including goodwill) in the balance sheet of that reporting unit. If this identifies a potential impairment then the second step is required. This requires assigning fair values to the assets and liabilities of the reporting unit (similar to what would be required under acquisition accounting). The difference between the fair value of these net assets and the estimate of the fair value of the reporting unit as a whole provides an implied fair value of the goodwill. If this implied fair value is less than the carrying value of the goodwill, then goodwill is impaired and an impairment charge requires to be recognised. In accordance with the requirements of the standard, the group performed its annual review at 30 September 2004. In addition, following a review of the impairment of goodwill relating to PacifiCorp under UK GAAP, the group has performed a review of the carrying value of the long-lived assets and goodwill allocated to the PacifiCorp reporting unit under US GAAP in accordance with FAS 144 Accounting for the Impairment or Disposal of Long-lived Assets and FAS 142, respectively. A two-step impairment test is also required under FAS 144. Under FAS 144, undiscounted cash flows for the long-lived assets of PacifiCorp exceeded their carrying value and accordingly no impairment was triggered. Under FAS 142 the carrying value of PacifiCorp (including goodwill) under US GAAP was determined to be in excess of its fair value, and accordingly the group has carried out an analysis to determine the implied value of goodwill. Fair value was determined under US GAAP using discounted cash flows and with reference to the price of comparable businesses, recent market transactions and estimated proceeds from disposal. As a result, a goodwill impairment charge of £1,381 million has been recorded in the PacifiCorp reportable segment under US GAAP reflecting the amount by which the carrying value of the goodwill exceeded its implied fair value. The impairment charge under US GAAP is £454 million higher than the charge under UK GAAP principally due to the higher carrying value of the net assets of PacifiCorp under US GAAP compared to UK GAAP. This is as a result of the recognition under US GAAP of regulatory assets, the impact of FAS 133 and lower cumulative amortisation of goodwill under US GAAP.

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US GAAP Derivative Financial Instruments

The group accounts for its derivative financial instruments under US GAAP in accordance with FAS 133, as amended. FAS 133 requires, for the purposes of US GAAP, all derivatives, as defined by the standard, to be recorded at fair value except for those which qualify for specific exemptions under the standard, such as the normal purchases and normal sales exception. Changes in the fair values of derivatives that are not designated as hedges are adjusted through earnings under US GAAP with the exception of long-term energy contracts that were in existence on 1 April 2001 and are included in PacifiCorp s ratemaking base. For these long-term energy contracts PacifiCorp received regulatory accounting orders to adjust the fair value through regulatory assets or liabilities, reversing recorded amounts as the contracts settle. For derivatives designated as effective cash flow hedges, the changes in fair values are recognised under US GAAP in accumulated other comprehensive income until the hedged items are recognised in earnings. For derivatives designated as effective fair value hedges, the changes in fair values are recognised under US GAAP in the income statement, offset to the extent that they are effective, by fair value movements on the designated risk of the item being hedged. The group s future results under US GAAP could be impacted by changes in market conditions to the extent that changes in contract values are not offset by regulatory or hedge accounting.

The group s valuation policy for derivative and other financial instruments is to utilise, as much as possible, quoted prices in an active trading market.

Futures, swaps and forward agreements are valued against the appropriate market-based curves. Forward price curves are developed using market prices from independent sources for liquid commodities, markets and products and modelled for illiquid commodities, markets and products.

Structured transactions are disaggregated into their traded core components, and each component is valued against the appropriate market-based curves. For transactions where a market price for the point of delivery is not actively quoted, if possible, the transaction is valued at the most appropriate point of delivery where a market price exists with appropriate adjustments for the actual point of delivery, including, if applicable, currency adjustments.

In the absence of quoted prices for identical or similar assets or liabilities, it is sometimes necessary to apply valuation techniques where contracts are market to approved models. Models are used for developing both the forward curves and the valuation metrics of the instruments themselves where the instruments are complex combinations of standard and non-standard products. All models are subject to rigorous testing prior to being approved for valuation and subsequent continuous testing and approval procedures designed to ensure the validity and accuracy of the model assumptions and inputs. To the extent that observable market or transaction data for a contract indicates that an assumption should be adjusted, this is treated as a change in estimate.

US GAAP Pensions and Other Post-Retirement Benefits

The group accounts for its pension schemes under US GAAP in accordance with FAS 87 Employers Accounting for Pensions . Under FAS 87, certain of the group s pension schemes had assets with a fair value at 31 March 2005 that was less than the accumulated benefit obligation under the schemes at the same date. As a result, at 31 March 2005 the group recognised a minimum pension liability under US GAAP of £365 million, of which £216 million was charged to accumulated other comprehensive income and £149 million was recognised as a US regulatory asset. If a discount rate had been used for accumulated benefit obligation purposes which was 0.5% p.a. higher than that actually used, the impact would have been to reduce the minimum pension liability by £47 million in respect of the group s UK pension schemes and £43 million in respect of the group s US pension schemes. The discount rates used for the purposes of US GAAP for the group s principal pension schemes are set out in Table 43.

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13 Accounting Developments

UK GAAP Developments Applicable for the Year to March 2005

During the year ended 31 March 2005 the UK Accounting Standards Board (ASB) issued a number of new standards which were not required to be implemented in 2004/05 as they form part of the ASB s convergence programme to align UK GAAP with IFRS over time.

From 2005/06, however, ScottishPower will be required to prepare its consolidated Accounts in compliance with IFRS rather than UK GAAP and it will, therefore, be the international equivalents that the group will be required to apply in its 2005/06 Accounts. The impact of IFRS on the group is discussed in Section 14 on page 64.

US GAAP Developments Applicable for the Year to March 2005

In May 2004, the Financial Accounting Standards Board (FASB) released FASB Staff Position (FASB SP) No. 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 . FASB SP No. 106-2 provides guidance on the accounting for the effects of the Medicare Act. The Medicare Act introduced a prescription drug benefit under Medicare, as well as a federal subsidy to sponsors of retiree health plans which include prescription drug benefits.

Employers that sponsor post-retirement healthcare plans that offer prescription drug benefits must determine if their prescription drug benefits are actuarially equivalent to the drug benefit provided under Medicare Part D as of the date of

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enactment of the Medicare Act to be entitled to receive the subsidy. Employers are required to disclose the effect of the federal subsidy afforded by the Medicare Act if its prescription drug benefits are determined to be actuarially equivalent to the Medicare Part D benefit. FASB SP No. 106-2 was effective for the first interim period or annual period beginning after 15 June 2004. Adopting FASB SP No. 106-2 did not have a material impact on the group s results and financial position under US GAAP.

US GAAP Developments Applicable in the Future

In January 2005, the Centers for Medicare and Medicaid Services released final regulations for implementing the Medicare Act. These regulations provide guidance for making a determination of whether the benefits under a plan will meet the definition of actuarial equivalence. As this was subsequent to PacifiCorp s measurement date, these regulations had no impact on the year ended 31 March 2005. The group does not expect these regulations to have a material impact on the group s results and financial position under US GAAP during the year ending 31 March 2006.

In June 2004, the Emerging Issues Task Force (EITF) issued EITF No. 03-1, The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments . Application guidance in EITF No. 03-1 should be used to determine whether an investment is considered impaired, whether an impairment is other than temporary, and the measurement of any such impairment. The guidance also includes accounting and disclosure considerations. In September 2004, the FASB issued FASB EITF No. 03-1-1, Effective date of paragraphs 10-20 of EITF No. 03-1, The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments . FASB EITF No. 03-1-1 delayed the previously required effective date of 1 July 2004 for the group regarding the measurement and recognition guidance contained in the applicable paragraphs. The delay of the effective date is likely to be superseded with the final issuance of a FASB Staff Position on other-than-temporary impairments of investments. The adoption of the measurement and recognition guidance of EITF No. 03-1, if implemented in its present form, is not anticipated to have a material impact on the group s results and financial position under US GAAP.

In November 2004, the FASB issued FAS 151, Inventory Costs . FAS 151 requires that abnormal amounts of idle facility expense, freight, handling costs and wasted material (spoilage) be included as current-period charges, eliminating the option for capitalisation. This statement is effective for inventory costs incurred after 1 April 2006. This statement is not expected to have a material impact on the group s results and financial position under US GAAP.

In December 2004, the FASB issued FAS 153, Exchanges of Non-monetary Assets , which amends Accounting Principles Board (APB) Opinion No. 29, Accounting for Non-monetary Transactions . FAS 153 eliminates the exception from fair value measurement for non-monetary exchanges of similar productive assets in APB No. 29 and replaces it with an exception for exchanges that do not have commercial substance. This statement specifies that a non-monetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. This statement is effective for any exchanges of non-monetary assets that occur after 1 April 2006. This statement is not expected to have a material impact on the group s results and financial position under US GAAP.

In December 2004, the FASB issued FAS 123R, Share-Based Payment , a revision of the originally issued FAS 123 Accounting for Stock-Based Compensation . FAS 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. In March 2005, the SEC issued Staff Accounting Bulletin (SAB) 107, which provides additional guidance in applying the provisions of FAS 123R. FAS 123R requires that the cost resulting from all share-based payment transactions be recognised in the financial statements using the fair value method. The intrinsic value method of accounting established by APB No. 25 Accounting for Stock-Based Compensation will no longer be allowed. SAB 107 describes the SEC staff s expectations in determining the assumptions that underlie the fair estimates and discusses the interaction of FAS 123R with other existing SEC guidance. In April 2005, the effective date of FAS 123R was deferred until the beginning of the financial year that begins after 15 June 2005, however early adoption is encouraged. A modified prospective application is required for new awards and to awards modified, repurchased or cancelled after the required effective date. The provisions of SAB 107 will be applied upon adoption of FAS 123R. The adoption of this statement is not expected to have a material impact on the group s results and financial position under US GAAP.

In December 2004, the FASB issued FASB SP No. 109-1, Application of FASB Statement No. 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities Provided by the American Jobs Creation Act of 2004 . This tax deduction will be treated as a special deduction as described in FAS 109, Accounting for Income Taxes . As such, the special deduction has no effect on deferred tax assets and liabilities existing at the enactment date. Rather, the impact of this deduction will be reported in the period in which the deduction could be claimed on a separate return basis in accordance with the group s accounting policy. FASB SP No. 109-1 became effective upon issuance. The impact of the deduction to the group will depend on the application of forthcoming guidance from the Internal Revenue Service and therefore the group continues to evaluate the effect that FASB SP No. 109-1 will have on its results and financial position under US GAAP.

In March 2005, the FASB issued Financial Interpretation

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No. (FIN) 47 Accounting for Conditional Asset Retirement Obligations . FIN 47 clarifies that the term conditional asset retirement obligation as used in FAS 143, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. FIN 47 clarifies that an entity is required to recognise a liability for the fair value of a conditional asset retirement obligation when incurred if the liability s fair value can be reasonably estimated.

FIN 47 is effective at the end of the financial year ending after 15 December 2005. The group is currently evaluating the impact of adopting FIN 47 on its results and financial position under US GAAP.

14 Implementation of International Financial Reporting Standards

IFRS Transition - Introduction

In June 2002, the European Union (EU) adopted Regulations which require that the consolidated accounts of listed companies in the EU should, from 2005, be presented in accordance with EU-adopted IFRS and IAS, collectively referred to below as IFRS .

ScottishPower is required to present its consolidated Accounts for the first time in accordance with IFRS for the financial year commencing 1 April 2005 and, from that date, the group s Accounts will no longer be prepared in accordance with UK GAAP. The group s first published quarterly Accounts prepared in accordance with IFRS will be those for the quarter ending 30 June 2005, due to be published in August 2005.

The SEC has adopted amendments to Form 20-F to allow foreign private issuers such as ScottishPower, to provide in their SEC filings two years rather than three years of audited financial statements prepared on a consistent basis of accounting. The group has therefore decided to take advantage of this concession and adopt a transition date of 1 April 2004.

has also been provided. This IFRS financial information will form the basis of the comparative information which will be included in the group s first Annual Accounts prepared in accordance with IFRS for the year ending 31 March 2006. The information on pages 173 to 184 has been audited and the independent auditors report is set out on page 185.

The financial information referred to above does not include any adjustments for IAS 32 and IAS 39 which are being applied by the group with effect from 1 April 2005 in accordance with the transitional arrangements set out in IFRS 1 First-time Adoption of International Financial Reporting Standards . Further information regarding the impact of these standards is contained on pages 68 to 70 and on pages 187 to 190.

The effect of moving from UK GAAP to IFRS has increased group profit before taxation by £127.7 million for the year ended 31 March 2005, principally due to the cessation of amortisation of goodwill which increased operating profit by £117.5 million. Earnings per share, before goodwill amortisation and the exceptional item, reduced by 0.42 pence. The group s net assets have reduced by £80.6 million as at 31 March 2005 mainly as a result of recognition of the assets and liabilities of the group s pensions and other post-retirement benefits, net of deferred tax, offset by the cessation of goodwill amortisation. Net debt under IFRS increased by £159.3 million to £4,306.3 million, primarily as a result of the grossing up of £88.5 million of non-recourse debt relating to the group s US finance lease arrangements which was included within debtors under UK GAAP, as the financing qualified for linked presentation. Additional finance lease obligations of £70.8 million have been recognised due to the recently issued International Financial Reporting Interpretations Committee (IFRIC) 4 Determining Whether an Arrangement Contains a Lease . Whilst this impacts on what is reported as net debt, cash flows are unaffected. Other than pensions and other post-retirement benefits and goodwill, the adjustments discussed below are not material.

The rules for first-time adoption of IFRS are contained within IFRS 1, which requires that the group should use the same accounting policies in its opening IFRS balance sheet and throughout all periods presented in its first IFRS financial statements. These policies are required to comply with IFRS effective at the reporting date of ScottishPower s first published financial statements under IFRS as at 31 March 2006. Due to a number of new and revised standards included within the standards that comprise IFRS, there is not yet a significant body of established practice on which to draw in forming opinions regarding interpretation and application. Accordingly, practice is continuing to evolve. At this preliminary stage, therefore, the full financial effect of reporting under IFRS as it will be applied and reported on in the group s first IFRS financial statements for the year ending 31 March 2006 may be subject to change.

Overview of IFRS Reconciliations

Detailed reconciliations of the group s income statement for the year ended 31 March 2005 and balance sheets as at 1 April 2004 (the group s date of transition to IFRS) and 31 March 2005 under IFRS to the results and financial position previously reported under UK GAAP, have been included within the IFRS Financial Information section, to assist in understanding the nature and quantum of the differences between the two reporting bases. In addition, the group s cash flow statement under IFRS for the year ended 31 March 2005, together with a narrative explanation of the main differences from UK GAAP,

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On transition to IFRS, the group has taken advantage of the following exemptions contained within IFRS 1:

Ø Business combinations: The group has elected not to restate business combinations accounted for prior to 1 April 2004, the group s date of transition to IFRS. Acquisitions after this date, namely Damhead Creek and Brighton power station, have been restated to comply with IFRS 3 Business Combinations ;

Ø Revaluation as deemed cost: Manweb distribution assets, which were last revalued in 1997, have been deemed to be recorded at cost;

Ø Employee benefits: The cumulative actuarial losses relating to pensions and other post-retirement benefits at the date of transition to IFRS have been recognised in retained earnings;

Ø Financial instruments: The group has elected not to prepare comparative information in accordance with IAS 32 and IAS 39. These standards will be applied with effect from 1 April 2005. Details of the group s IAS 32 and IAS 39 opening position are presented later in this section on pages 68 to 70; and

Ø Share-based payment: The group has applied IFRS 2 Share-based Payment to equity instruments granted after 7 November 2002 only.

The group has elected not to take advantage of the IFRS 1 exemption to reset the foreign currency translation reserve to zero at the date of transition to IFRS and has therefore transferred £484.6 million from retained earnings to the newly created translation reserve. This represents the benefit of our balance sheet hedging strategy which will be reflected in the group s income statement on completion of the sale of PacifiCorp.

Overview of Other IFRS Information

The group s IFRS accounting policies as they have been applied for the year ended 31 March 2005 are set out on pages 173 to 178.

These accounting policies have been adopted based on all IFRS and IFRIC interpretations issued by the International Accounting Standards Board (IASB) as at the date of this report and which have either been approved by the EU or are more likely than not to be approved by the EU by the time the group prepares its first Annual Accounts in accordance details of the comparative figures that will be published in each of the quarters during the year ending 31 March 2006.

Whilst these numbers do not include the impact of IAS 32 and IAS 39, which are being applied with effect from 1 April 2005, pages 68 to 70 provide further details of the impact of these standards on the group, including the IAS 32 and IAS 39 opening position at 1 April 2005. In addition, a summary of the IAS 32 and IAS 39 accounting policies are also provided on pages 187 to 190 for information.

IFRS Summary of Impact

Presentation of IFRS Financial Statements

In reconciling from UK GAAP to IFRS, the format of the group income statement and the group balance sheet have been adjusted to reflect reclassifications that would be required to comply with IAS 1 Presentation of Financial Statements . As the income statement forms part of the reconciliation from UK GAAP to IFRS, certain of the headings will not be required when the group reports its income statement under IFRS in its first full IFRS financial statements for the year ending 31 March 2006.

IFRS Remeasurements

The remeasurement adjustments that have been made to the amounts previously reported under UK GAAP are discussed in detail below:

Ø **Dividends**

Under UK GAAP, dividends proposed after the balance sheet date are accrued in the balance sheet. Under IFRS, these dividends are not accrued until the date at which they are declared. This adjustment, which is merely a timing difference, has increased net assets by £139.4 million at 31 March 2005.

Ø **Income Taxes**

Under UK GAAP, deferred tax is provided based on timing differences, whilst IFRS has a wider scope and requires deferred tax to be provided on all temporary differences. The group s IFRS balance with IFRS for the year ending 31 March 2006. In particular, this assumes that the EU will adopt revised IAS 19 (2004)   Employee Benefits   issued by the IASB in December 2004 and IFRIC 4. It also assumes that the EU will not adopt IFRIC 3   Emission Rights   in its current form.

In addition, selected unaudited financial income statement data for the three months ended 30 June 2004, the six months ended 30 September 2004 and the nine months ended 31 December 2004 has been presented on page 186 to give further

sheet as at 31 March 2005 includes a reduction in the deferred tax liability of £172.1 million, primarily relating to the recognition of a further deferred tax asset on the pension deficit of £177.9 million. In addition, the income tax expense for the financial year ended 31 March 2005 has increased by £13.0 million, primarily as a result of an increase in the tax charge of £16.3 million due to the unwinding of temporary differences relating to previous acquisitions. This has led to a 1% increase in the group s effective tax rate, excluding the exceptional item, under IFRS compared to UK GAAP for the year ended 31 March 2005.

In accordance with the requirements of IFRS, additional deferred tax has been provided on the temporary differences arising on the acquisitions of Damhead Creek and Brighton

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power station as the recognition of assets and liabilities acquired at fair value differs to their tax base. This leads to additional deferred tax liabilities of £35.2 million being recognised under IFRS as at 31 March 2005.

Under UK GAAP, a deferred tax provision is made for tax which would arise on the remittance of the retained earnings of overseas subsidiaries, joint ventures and associated undertakings, only to the extent that dividends have been accrued as receivable or there is a binding agreement to distribute past earnings. IFRS requires deferred tax to be recognised on all retained earnings whose distribution is not within the control of the group or whose distribution is likely in the foreseeable future, irrespective of whether dividends have actually been accrued or declared. As the group has met the two conditions within IAS 12 Income Taxes for non-recognition of deferred tax on undistributed profits, no adjustment to the IFRS balance sheet has been made in this respect.

Ø Property, Plant and Equipment

Under UK GAAP, depreciation of property, plant and equipment is based on the cost or revalued amounts of the assets less the estimated residual value of the assets at the end of their useful economic lives. These residual values are based on prices prevailing at the time of acquisition or revaluation. Under IFRS, residual values are based on prices prevailing at each balance sheet date. Any changes in residual values impact the prospective depreciation charge. As a result of using updated residual values at 1 April 2004 on the transition to IFRS, the depreciation charge recognised under UK GAAP for the year ended 31 March 2005 has been reduced by £1.7 million.

Ø Leases

The group has finance leases where it acts as a lessor and funds these through non-recourse debt. Under UK GAAP, these are accounted for on a net cash investment basis and qualify for linked presentation whereby the non-recourse debt is offset against the receivable in accordance with FRS 5 Reporting the Substance of Transactions . Under IFRS, such leases are required to be accounted for as a receivable at an amount equal to the net investment in the lease and, unlike FRS 5, there is no concept of linked presentation in relation to non-recourse debt. The balance sheet has therefore been grossed up to present separately a finance lease receivable of £86.5 million and £88.5 million of non-recourse debt.

an increase in net debt of £70.8 million as a result of the inclusion of these additional finance lease obligations.

The total impact of IAS 17 has therefore led to an increase in net debt of £159.3 million. Underlying cash flows are not affected.

Ø Employee Benefits

Under UK GAAP, the group applied the provisions of SSAP 24 and provided detailed disclosures under FRS 17 in accounting for pension and other post-retirement benefits.

Under IFRS, accounting for pensions and other post-retirement benefits is significantly different from SSAP 24 and reflects, at each balance sheet date, the surplus or deficit in the pension scheme and other post-retirement benefit obligations. The group has applied the provisions of revised IAS 19 (2004) and, as such, actuarial gains and losses relating to these arrangements are recorded directly in retained earnings and will be presented in the statement of recognised income and expense. The additional provision, before deferred tax, recognised under IFRS amounts to £501.7 million at 31 March 2005. This results in a net liability for retirement benefits of £635.5 million at 31 March 2005. The effect of adopting revised IAS 19 (2004) on the group s income statement is to increase operating profit for the year ended 31 March 2005 by £14.3 million, reduce net finance costs by £0.6 million and hence increase profit before tax by £14.9 million. The resulting pensions and other post-retirement benefit costs for the year ended 31 March 2005, before the effect of capitalisation, are £69.0 million charged to operating profit and £0.2 million credited to net finance costs.

The level of costs for such arrangements will vary depending on, among other things, the benefits given to members and assumptions relating to interest rates, expected return on equities and mortality rates. As the balance sheet under IFRS reflects the deficit in the group s pension schemes and other post-retirement benefit arrangements, changes in these amounts due to, among other things, changes in investment value, interest rates and actuarial assumptions, will impact reported net assets. The information regarding pensions has been previously disclosed in our Annual Report & Accounts. The group has decided not to adopt the corridor approach under IAS 19 and will continue to show the full surplus or deficit of the group s pension schemes and other post-retirement benefit arrangements on the balance sheet going forward.

Ø Share-based Payment

IFRIC 4 contains specific guidance on the identification of lease arrangements and is of particular relevance to the power industry. Adoption of IFRIC 4 is not mandatory for the group until 1 April 2006 but ScottishPower has, as permitted, adopted it from 1 April 2004 in order to assist comparability. The arrangements, which have been identified as leases under IFRIC 4, have been assessed against the criteria contained in IAS 17 Leases to determine whether they should be categorised as operating or finance leases. This has resulted in

Under UK GAAP, the group accounts for its share and share option schemes based on an intrinsic value basis, except for the group s Sharesave scheme which is excluded from these accounting requirements. Under IFRS, the Sharesave scheme is included, and application of the fair value model for assessing the value of share-based payments results in a different charge to the income statement. The impact of applying IFRS 2 has been to increase operating profit for the year ended 31 March

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2005 by £0.4 million. The resulting cost for share-based payments in the year ended 31 March 2005 is £6.8 million. The cost is reduced compared to UK GAAP as IFRS 2 is only required to apply to share and share option awards granted after 7 November 2002. In future years, the cost of share schemes will increase under IFRS 2 as more awards come within the scope of the standard. The amount of future cost will vary depending on the nature of the group s share and share option arrangements in those years.

Ø Goodwill

Under UK GAAP, goodwill is required to be amortised over its estimated useful economic life. On transition to IFRS, the balance of goodwill recognised under UK GAAP at that date is frozen and no future amortisation is charged. However, the goodwill is subject to a mandatory impairment test on at least an annual basis and otherwise if there is any indication of impairment. The goodwill amortisation of £117.5 million for the year ended 31 March 2005 has therefore been reversed in the income statement under IFRS. This, together with the consequential foreign exchange impact, is reflected in a balance of goodwill of £885.1 million at 31 March 2005 under IFRS compared to £765.2 million under UK GAAP.

Ø Impairment of Goodwill

The goodwill associated with PacifiCorp has been reviewed for impairment under both UK GAAP and IFRS, as required where there is an indicator of impairment. This resulted in a charge for impairment under IFRS which is £5.0 million lower compared to the charge under UK GAAP, as a result of the lower net assets of PacifiCorp under IFRS.

On 24 May 2005 the group announced the sale of PacifiCorp. In the Accounts for the year ending 31 March 2006, PacifiCorp will be classified as a discontinued operation under IFRS 5 Non-current Assets Held for Sale and Discontinued Operations . This will result in the net income of PacifiCorp being disclosed as a single line item within the income statement, and the aggregation and separate disclosures of assets and liabilities on the balance sheet.

Ø Business Combinations

The fair values attributed under IFRS to deferred tax and intangible assets on the acquisitions of Damhead Creek and Brighton power station differ from those under UK GAAP. Accordingly, the amount recognised for amortisation of the intangible assets under IFRS compared to UK GAAP is higher by £10.0 million and is included within cost of sales.

Ø Associates/Jointly Controlled Entities

Under UK GAAP, the group s share of the operating profit, interest and taxation of associates and jointly controlled entities is required to be shown separately in the income statement. Under IFRS, the group s share of the post-tax results of associates and jointly controlled entities is included within operating profit as the operations are closely related to those of the parent and other subsidiaries. Whilst profit for the financial year remains unchanged, this has resulted in a £6.0 million decrease in operating profit for the year ended 31 March 2005.

Ø Intangible Assets

Computer software Under UK GAAP, capitalised computer software of £238.6 million is included within tangible fixed assets on the balance sheet as at 31 March 2005. Under IFRS, capitalised computer software is recorded as an intangible asset.

Hydroelectric relicensing costs Under UK GAAP, hydroelectric relicensing costs of £62.5 million are included within the cost of the related hydroelectric asset as at 31 March 2005. Under IFRS, these costs are separately recorded as intangible assets.

Neither of the above reclassifications have an effect on the amortisation of these costs through the IFRS income statement for the year ended 31 March 2005 or going forward.

Ø Provisions

Under UK GAAP, provisions are required to be shown within one caption on the balance sheet. Under IFRS, provisions due within one year and those due after more than one year are required to be shown separately on the face of the balance sheet. Consequently, provisions due within one year of £80.1 million have been separately classified on the balance sheet.

Ø Foreign Currency Debt

Under UK GAAP, all debt denominated in foreign currencies has been retranslated using the exchange rate specified in the related hedge contract. IAS 21 The Effects of Changes in Foreign Exchange Rates requires that all financial instruments be separately measured and presented at the closing balance sheet rate. As a result, foreign currency debt is translated at the closing exchange rate and the group s related derivatives have been separately presented on the

IFRS Reclassifications

In addition to the above, a number of reclassification adjustments have been made to the income statement and balance sheet. These have no effect on either net income or net assets. The principal reclassifications from UK GAAP to IFRS are:

balance sheet rather than disclosing the net hedged position that exists under UK GAAP. Therefore, under IFRS, derivatives currently showing a gain as at 31 March 2005 of £37.5 million and £11.6 million have been included within non-current and current trade and other receivables, respectively. Derivatives currently showing a loss are valued at £2.7 million and £17.9 million and have been reclassified from loans and other borrowings and included within non-current and current trade and other payables, respectively. The group s net debt calculation will be adjusted to take account of this change in presentation resulting in no change to reported net debt.

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Ø **Other**

Balances relating to pensions and other post-retirement benefits, translation reserve, leases and current taxation have been shown separately on the face of the balance sheet prepared under IFRS. In addition, the current and non-current balance of trade and other receivables and finance lease receivables have been presented separately on the face of the balance sheet.

Summary of IAS 39 Impact

Both IAS 32 and IAS 39 will be applied by ScottishPower with effect from 1 April 2005 and are therefore not included in the reconciliations set out on pages 179 to 184. IAS 32 sets out the presentation requirements for debt and own equity instruments and also the disclosure requirements for financial instruments and IAS 39 sets out the accounting requirements for financial instruments. The definition of financial instruments in IAS 39 captures certain commodity contracts (including energy), loans and borrowings, trade receivables and payables, investments and cash as well as derivatives. There has been no equivalent standard prior to 1 January 2005 within UK GAAP but the group has, for some years, accounted for its derivative financial instruments under US GAAP in accordance with FAS 133. Although there are similarities in the conceptual basis underpinning both IAS 39 and FAS 133, there are differences in definition, scope and other specific rules. Accordingly, the group s reported FAS 133 amounts should not be taken as representative of those amounts the group may report in future under IAS 32 and IAS 39.

The group has adopted the full IASB versions of IAS 32 and IAS 39 in line with the recommendations of the ASB. The sections of IAS 39 which were carved out by the EU do not have any impact on the group.

Energy Commodity Contracts

IAS 39 captures commodity contracts that do not meet the criteria for own use . These commodity contracts are treated as derivatives and have to be fair valued. To prove that commodity contracts meet the own use criteria, the entity must demonstrate that the contracts are for normal business requirements, are not exchangeable for other commodities or financial instruments, and result in physical delivery of the commodity. Whilst many of the group s commodity contracts meet these tests, a substantial number do not, given the flexibility inherent in the group s gas and power portfolios and, therefore these contracts fall within the scope of IAS 39 and are subject to fair value accounting.

subsequently matched in the income statement on settlement of the hedge transactions, minimising earnings volatility from movements in fair value to the extent the hedge is effective. Regardless of whether or not hedge accounting is available, changes in fair value will impact reported net assets. Fair value is estimated by calculating the present value of the difference between the prices in the contract and the applicable forward price curve. Forward price curves used are consistent with those used for FAS 133 accounting.

Adopting IAS 39 will not alter the group s balanced economic hedging strategy, nor underlying contract cash flows. The principal contributors to the group s opening IAS 39 position are as follows:

Ø Gas is purchased under short- and long-term contracts to meet the needs of gas-fired generation plants, in the UK and US, and UK retail gas customers. Although the retail gas customer sales contracts achieve own use treatment, the flexibility inherent in the purchase contracts precludes them from being accounted for in this manner. As a consequence, such contracts are subject to fair value accounting, some of which will meet the requirements necessary to qualify for hedge accounting treatment.

Ø PacifiCorp has entered into a number of long-term energy contracts to meet its future retail load requirements and, due to the regulatory environment in which it operates, is permitted to recover the underlying costs of these contracts through rates charged to customers. Since these contracts do not meet the criteria for own use designation, they are recorded at fair value. Movements in contract fair values have no effect on either contractual cash flows or cash flows receivable from customers.

Table 44 shows the effect of implementing IAS 39 as it relates to energy commodity contracts on the group s IFRS balance sheet at 1 April 2005. These adjustments reflect the incremental adjustment required to the UK GAAP balance sheet at 31 March 2005.

On implementation of IAS 39, the group s net assets under IFRS have increased by £252 million, net of deferred tax of £86 million, in respect of energy-related contracts which do not qualify for own use designation. This includes the reversal of UK GAAP amounts in relation to contracts which will be subject to IAS 39 from 1 April 2005. The increase in net assets of £252 million is reflected in a reduction in retained earnings of £90 million and the establishment of a hedge reserve balance of £342 million. The opening value together with subsequent movements in the value of contracts which do not qualify for hedge accounting, will unwind through the income statement over time. Any movements in the fair value of contracts which qualify for hedge accounting will be offset within the hedge reserve and released to the income statement on settlement of the underlying hedged transactions.

IAS 39 requires any changes in fair value of a derivative to be taken to the income statement, except in circumstances where an effective cash flow hedging relationship is established and maintained against a highly probable forecast transaction. In these instances, fair value changes are initially taken directly to a hedge reserve within shareholders equity and

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Ø **Table 44**

Incremental effect of IAS 39 on energy-related contracts at 1 April 2005 (£m)

	PacifiCorp	PPM Energy	UK Division	**Commodity Total**
IAS 39 assets/(liabilities)	(184)	6	532	**354**
Onerous contracts/intangible assets reversal			(16)	**(16)**
Deferred tax assets/(liabilities)	71	(2)	(155)	(86)
Total net assets/(liabilities)	**(113)**	**4**	**361**	**252**
Fair value deferred in hedge reserves	36		306	**342**
Fair value impact on retained earnings	(149)	4	55	**(90)**
Total reserves movement	**(113)**	**4**	**361**	**252**

Based on the group s contract portfolio at 1 April 2005 and designated hedge accounting relationships, a 1% movement in forward price curves would result in a pre-tax fair value movement of £32 million of which £13 million would be reported through the income statement.

Treasury

IAS 39 also applies to the group s treasury activities. Table 45 shows the effect of implementing IAS 39 as it relates to treasury-related contracts on the group s IFRS balance sheet at 1 April 2005. These adjustments reflect the incremental adjustment required to the UK GAAP balance sheet at 31 March 2005.

The group s loans, borrowings and derivatives portfolio are financial instruments within the scope of IAS 39. IAS 39 requires loans and borrowings to be accounted for on the basis of amortised cost, in line with the accounting treatment under UK GAAP. The group also enters into a number of derivative financial instruments in the normal course of business to manage movements in exchange rates and interest rates impacting earnings, cash flows and the US net investment on consolidation. These contracts will now be subject to fair value accounting which will impact the timing of recognition of interest rate benefits, although the group s economic policy of hedging against foreign exchange movements in its US net assets will continue.

Under UK GAAP, the group s US convertible bonds were accounted for as dollar-denominated liabilities and are part of

Ø **Table 45**

Incremental effect of IAS 39 on treasury-related

contracts at 1 April 2005 (£m)

the dollar liabilities hedging the group s US net assets. Under IAS 39, these liabilities will continue to form part of the hedging relationship of the US net investment on consolidation. They require to be accounted for as US dollar liabilities with the foreign exchange and equity-linked embedded derivative components of the convertible bonds separately identified, and measured at fair value through the income statement. The impact of accounting for the convertible bonds in this way from 1 April 2005, compared to UK GAAP, is to increase the effective interest charge in the income statement and introduce changes to net debt and the income statement through movements in fair value of the embedded derivative.

The group notes that the IASB is proposing to amend sections of IAS 39 that allow companies to carry designated financial instruments at fair value. If the proposed amendment to IAS 39 is implemented by the IASB and subsequently endorsed by the EU, the group may be able to designate the convertible bonds as financial liabilities held at fair value. Until such time as this may happen, however, the group will continue to apply the accounting described above for the convertible bonds.

IAS 39 restricts foreign currency hedging to cash flows denominated in a currency other than the functional currency of the entity entering into the transaction. Therefore the group s previous strategy of hedging expected US dollar profits using US dollar forwards will no longer operate as a hedge from 1 April 2006. Subject to EU approval, transitional provisions will enable the group to continue to hedge dollar revenues as an alternative for financial year 2005/06 only.

The group has hedged part of its investment in US net assets by the use of cross-currency swaps, and uses interest rate swaps to protect results from interest rate movements. IAS 39 does not permit hedge accounting for hedge instruments that are matched to other hedge instruments and the interest rate swaps will therefore be fair valued through the income statement after adoption of IAS 39. There are a number of other positions which, due to effectiveness test criteria, require to be fair valued.

On implementation of IAS 39, the group s net assets under IFRS have increased by £16 million, net of deferred tax of £5 million in respect of treasury-related contracts. This increase in

	Treasury
IAS 39 assets	21
Deferred tax liabilities	(5)
Total net assets	**16**

Fair value deferred in hedge reserves	33
Fair value impact on retained earnings	(17)
Total reserves movement	**16**

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net assets of £16 million is reflected in a reduction in retained earnings under IFRS of £17 million and an increased hedge reserve of £33 million.

Based on the group s treasury derivatives portfolio at 1 April 2005 and designated hedge accounting relationships, a 100 basis point movement in interest rate forward price curves would result in a pre-tax fair value movement of £22 million, of which £4 million would be reported through the income statement. A 10% movement in foreign exchange forward price curves would result in a pre-tax fair value movement of £117 million, of which £27 million would be reported through the income statement.

Available-for-sale Investments

In addition to financial instruments the group has various investments which were previously recorded at cost in the UK GAAP financial statements. Where these interests in other investments meet the definition of available-for-sale assets, IAS 39 requires that these be carried at fair value on the balance sheet, with any change in value being taken through equity. This is consistent with the US GAAP treatment of these investments. As at 1 April 2005, this would have reduced net assets by £2 million.

Summary of IAS 32 Impact

Minority Interests

Minority interests previously classified under UK GAAP as non-equity have been reclassified as liabilities under IAS 32. As at 1 April 2005, this would have reduced net assets by £53 million, and increased net debt by the same amount.

Summary of Combined IAS 32 and IAS 39 Impact

15 Off Balance Sheet Arrangements

The group has not entered into any transactions or arrangements which have given rise to off balance sheet obligations other than in respect of the following:

Operating Leases

The group has entered into various operating leases. In accordance with UK GAAP, future payments under these leases, amounting to £140.7 million at 31 March 2005 (March 2004: £69.9 million), are not recognised as liabilities in the group s balance sheet.

Derivative Contracts

The group has entered into various energy-related and treasury derivative contracts, primarily for hedging purposes. In accordance with UK GAAP, the value of derivatives held for hedging purposes are only recognised when the hedged item is recognised. This contrasts with US GAAP, which requires that derivatives, as defined in the relevant US accounting standards, are reflected as assets or liabilities at their fair values at the balance sheet date. An analysis of the group s derivatives, as defined under US GAAP, is set out in the Fair Value of Derivative Contracts section on page 57.

Guarantees

In the course of its ordinary business, the group has provided certain guarantees of its own performance. These guarantees are not expected to have a material impact on the group s financial position. In addition, in accordance with common practice, the group has provided guarantees of the performance of certain businesses and assets, which have been disposed of. The amounts guaranteed under these arrangements are significant in absolute value but the probability of these guarantees crystallising and resulting in a material change in the group s financial position is remote. The group has also entered into other arrangements in the normal course of business, which may crystallise as a result of events other than the group s non-performance of its contractual obligations. The probability of these guarantees giving rise to a material change in the group s financial position

The combined incremental effect of the implementation of IAS 32 and IAS 39 on the group s balance sheet at 1 April 2005, based on the portfolio of contracts in place at this date, was an increase in net assets of £213 million, net of deferred tax of £91 million, and an increase to net debt of £53 million.

Impact on Effective Tax Rate

The application of IAS 39 and the differing tax rates between the UK and the US, means that the effective tax rate, and resultant current/deferred tax split, will be impacted by the relative fair value movements arising across the group s UK and US operations and any current or deferred tax on fair value movements deferred in the hedge reserve.

is remote. Further details of these guarantees are provided in Note 34 to the Group Accounts.

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16 UK GAAP to US GAAP Reconciliation

The group s Accounts are prepared in accordance with UK GAAP, which differs in significant respects from US GAAP. Reconciliations of profit and equity shareholders funds between UK GAAP and US GAAP are set out in Note 34 to the Group Accounts. Under US GAAP, the loss for the year ended 31 March 2005 was £495 million, compared to a profit of £742 million in the previous year, before charging a cumulative adjustment for the effect of adopting FAS 143, net of tax, of £0.6 million. The loss per share under US GAAP was 27.02 pence per share compared to earnings per share, before the cumulative adjustment for FAS 143, of 40.57 pence per share in 2003/04. The loss per share under US GAAP was 27.02 pence per share compared to earnings per share in 2003/04 of 40.54 pence. Equity shareholders funds under US GAAP amounted to £4,794 million at 31 March 2005 compared to £5,730 million at 31 March 2004.

In addition to the review of the goodwill allocated to the PacifiCorp reporting segment under UK GAAP, the group performed a similar review under US GAAP and, as a result, a goodwill impairment charge of £1,381 million has been recorded in the PacifiCorp segment under US GAAP. The higher charge is principally due to the higher carrying value of the net assets of PacifiCorp under US GAAP compared to UK GAAP. This difference is primarily attributable to the recognition of regulatory assets, FAS 133 and lower cumulative amortisation of goodwill under US GAAP.

17 Summary

In the year, investment, business performance and our hedging strategy all contributed to delivering pre-tax profit, excluding goodwill amortisation and the exceptional item, of over £1 billion* for the first time. This performance has been reflected in the dividends for the full year, which have increased by 10% to 22.50 pence. Further to a strategic review of PacifiCorp, the Board concluded that shareholders interests were best served by a sale of PacifiCorp and the return of capital to shareholders. An exceptional goodwill impairment charge of £927 million was made to reduce the book value of PacifiCorp down to its expected net realisable value.

Reporting under IFRS has been successfully implemented at 1 April 2005 and we will report our first set of results on this basis in August 2005.

As we move forward our focus is on the continuing growth and development of the Infrastructure Division, UK Division and PPM Energy.

David Nish Finance Director

24 May 2005

* *Non-GAAP performance measure (see Cautionary Statement Regarding Non-GAAP Financial Information on page 72)*

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18 Cautionary Statement Regarding Non-GAAP Financial Information

ScottishPower management believes that the non-GAAP measures used by ScottishPower in the periods presented, when used in conjunction with other measures that are computed in accordance with UK GAAP, provide useful information to both management and investors and enhance an understanding of ScottishPower s reported results. As equal prominence is given to performance measures including and excluding goodwill amortisation and the exceptional item within the discussion included in this Annual Report & Accounts, ScottishPower management does not consider the inclusion of non-GAAP measures specifically relating to the exclusion of goodwill and the exceptional item or the presentation of EBITDA, disadvantages or materially constrains a reader s ability to assess ScottishPower s performance or liquidity.

Exclusion of Goodwill Amortisation and the Exceptional Item

ScottishPower management assesses the underlying performance of its businesses by adjusting UK GAAP statutory results to exclude items it considers to be non-operational or non-recurring in nature. In the periods presented, goodwill amortisation has been excluded because it is a recurring, non-operational item and the exceptional goodwill impairment charge has been excluded because it is a non-recurring item. ScottishPower management assesses the performance of its business excluding these items, enabling management to focus on the operational performance of the business. Therefore, to provide more meaningful information, ScottishPower has focused its discussion of business performance on the results excluding goodwill amortisation and the exceptional item. In the particular circumstances of the current financial year and the previous two financial years, the charge recognised for goodwill amortisation has remained broadly similar and, therefore, would not have significantly impacted year-on-year comparison of financial performance. The exceptional goodwill impairment charge is a prominent non-recurring item and, given its materiality, has been separately disclosed within the group s Profit and Loss Account, under UK GAAP.

Goodwill amortisation is a financially material item within ScottishPower s Accounts and is not common to all UK registered companies. The exceptional item is material and non-recurring as no impairment of goodwill has occurred in the last two years and there is no expectation of a further exceptional impairment charge for goodwill in the next two years. UK analysts and the business community in general regularly exclude goodwill amortisation and exceptional items when assessing and comparisons between the financial results of our business and other companies. Nonetheless, ScottishPower recognises that presenting performance measures which exclude goodwill amortisation and the exceptional item is additional disclosure to that required under UK GAAP. Furthermore, ScottishPower recognises that such non-GAAP performance measures should not be viewed as replacements for, or alternatives to, comparable GAAP measures, rather they should be considered as supplementary measures of ScottishPower s operating performance. In addition, the non-GAAP measures used by ScottishPower may differ from, and not be comparable to, similarly-titled measures used by other companies.

As ScottishPower management considers goodwill amortisation to be material and non-operational in nature and the exceptional item to be material and non-recurring in nature, it excludes these items from the primary financial indicators it uses for internal management reporting, forecasting, budgeting and planning purposes. In addition, the non-GAAP performance measures included herein are consistent with measures used to determine group dividend policy and to reward and incentivise senior management. ScottishPower has historically reported these non-GAAP performance measures to the investment community and believes that their inclusion provides consistency in its financial reporting. Looking forward, implementation of IFRS 3, discussed in Section 14, will prohibit the amortisation of goodwill and instead will require an impairment test to be performed on at least an annual basis. This will remove the goodwill amortisation charge currently reported as part of the group s Profit and Loss Account.

Presentation of EBITDA and EBITDA excluding the Exceptional Item

Management and external credit rating agencies also utilise a number of financial ratios when assessing the performance of ScottishPower and the group s financing arrangements are also subject to a number of ratio-based covenants contained within its principal credit agreements, one of which is EBITDA, excluding the exceptional item. EBITDA and EBITDA, excluding the exceptional item, are non-GAAP liquidity measures, and, as such, should not be viewed as replacements for, or alternatives to, comparable GAAP measures; rather they should be considered as supplementary measures of ScottishPower s liquidity position and may not be comparable to similarly-titled measures used by other companies.

forecasting the results of UK companies. Presenting ScottishPower s results both including and excluding these non-operational and non-recurring items, ensures investors are in a position to make fair and equitable

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Risk Factors

1 Introduction

There are risks and uncertainties inherent in the group s business. These risks could materially affect the group s business, its turnover, operating profit, net assets, liquidity and capital resources. The risk management processes established by the group are designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in the group s business and activities; measure quantitative market risk exposure; and identify qualitative market risk exposure in its business. Increases or reductions in future retail demand for electricity as a result of economic growth or downturns, among other factors, including abnormal weather, may impact retail revenues, cash flows and investment levels.

The sale of PacifiCorp may not progress or conclude as expected.

The sale of PacifiCorp is subject to US Securities and Exchange Commission, Department of Justice or Federal Energy Regulatory Commission (FERC), Federal Trade Commission and Nuclear Regulatory Commission approvals at the federal level, without conditions that would have a material adverse effect on the PacifiCorp business. In addition it is subject to approval at state level in Utah, Oregon, Wyoming, Washington, Idaho and California provided such state approvals are not subject to conditions whose effect would be meaningfully adverse to the business of PacifiCorp. The sale is subject to further conditions to completion which include the representations and warranties of the parties remaining true and correct, the parties performing their covenants and obligations under the agreement in all material respects, and no material adverse effect in relation to PacifiCorp having occurred. The agreement may

2 Risks Relating to the Group s Business

The assets and business processes of the group may not perform as expected, which could impact the group s ability to meet its obligations, including obligations to its investors.

The group s assets and mechanical systems, as well as its business processes and procedures, might not perform as expected. This may result in the group being unable to meet its obligations without resorting to an unanticipated market transaction and may lead to loss of revenue and a reduction in profitability.

be terminated prior to completion by mutual agreement of the parties or otherwise in certain circumstances including material breach of the representations, warranties or covenants of the parties, ScottishPower shareholders not approving the sale or the sale not having been completed by 23 May 2006 or in certain circumstances by 17 February 2007 and (by MidAmerican) where the Board of ScottishPower withdraws or adversely modifies its recommendation of the sale.

Changes in federal and state regulatory requirements in the US could negatively affect the group s turnover or profitability.

In the US, the group is subject to the jurisdiction of federal and

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Risk Factors

state regulatory authorities. The FERC establishes tariffs under which PacifiCorp provides transmission services to the wholesale market and the retail market for states allowing retail competition, establishes both cost-based and market-based tariffs under which PacifiCorp sells electricity at wholesale and has licensing authority over most of PacifiCorp s hydroelectric generation facilities. In each state in which PacifiCorp operates, the utility regulatory commissions independently determine the rates PacifiCorp may charge its retail customers in that state.

Each state s rate setting process is based upon that commission s acceptance of an allocated share of PacifiCorp s total costs as such state s responsibility . When different states adopt different methods to address this inter-jurisdictional cost allocation issue, some costs may not be incorporated into any rates in any state. Ratemaking is done on the basis of normalised costs, so if, in a specific year, realised costs are higher than normal, rates will not be high enough to cover those costs. Likewise, if, in a given year costs are lower than normal or revenues are higher, PacifiCorp retains the resulting higher-than-normal profit. Each state commission sets rates based on a test year presented by a company in accordance with commission rules. In states that use a historical test year, rate adjustments can follow historical cost increases, or decreases, by up to two years. Regulatory lag requires PacifiCorp to incur costs, including those for new investments, for which recovery through rates is delayed. Further, each state commission decides what levels of expense and investment are necessary, reasonable and prudent in providing service. In the event that a state commission decides that part of PacifiCorp s costs do not meet this standard, such costs will be disallowed and not recovered in rates. For these reasons, the rates authorised by the regulators may be less than the costs incurred by PacifiCorp to provide electrical service to its customers in a given period.

Changes in national regulatory requirements in the UK could negatively affect the group s turnover or profitability.

In the UK, the electricity and gas industries are regulated primarily through powers assigned, under the Utilities Act 2000, to the Gas and Electricity Markets Authority (the Authority) which licenses industry participants, enforces licence conditions, regulates quality of service and sets pricing formulae for electricity transmission and distribution activities. In principle, the Authority has wide discretion in the exercise of its obligation to act to protect the interests of customers, by promoting effective competition wherever appropriate. Ensuring that licence holders are able to finance their functions is only one of a number of other factors which the Authority must consider. Hence, the Authority imposes limitations on the rates the group can charge and seeks to promote competition in certain of the group s markets. Future regulatory changes in the UK may negatively affect the group s compliance costs, its business, results of operations or financial condition.

Pending legislation in the US could have currently unpredictable effects on the nature and extent of regulations to which the group is subject and on its revenues or profitability.

In the US, PacifiCorp and PPM Energy conduct business in conformance with a multitude of federal and state laws. During the past several years, the United States Congress has had, and continues to have, under active consideration, significant changes in energy and air quality policy. For example, comprehensive energy legislation could possibly change the hydroelectric relicensing process under the Federal Power Act, repeal the Public Utility Holding Company Act (PUHCA) and encourage investment in renewable and lower-emission coal generation. The late-2004 extension to 31 December 2005 of the renewable energy Production Tax Credit might be further extended. Energy tax credits may have significant influence in PPM Energy s business planning. Changes to the Clean Air Act contemplated by a variety of pending legislative proposals are being monitored closely as they may impact requirements for emissions from fossil-fuelled generation plants, although the Clear Skies Act and other proposals remain deadlocked in a Senate committee. The Clear Skies Act and other air quality initiatives could require additional control of emissions from PacifiCorp s fossil-fuelled generation plants, which would increase PacifiCorp s costs or lower electricity generation output.

The laws of the states in which PacifiCorp operates affect the generation, transmission and distribution of electricity. The state legislatures continue to make adjustments to the legislation covering PacifiCorp s activities but the broad thrust of recent changes is to clarify resource procurement, taxation, resource allocation and inter-utility service territory procedures and the changes are not thought likely to have a significant adverse impact on PacifiCorp s operations. Indeed, some may clarify issues and increase the certainty of recovery for a range of investments and expenses.

The group cannot be certain of the extent or timing of the general trend towards tightening regulation of environmental impact and may, therefore, fail to meet predicted turnover or profitability.

Federal, state and local authorities regulate many of the group s US activities pursuant to laws designed to restore, protect and enhance the quality of the environment. PacifiCorp and PPM Energy cannot predict what material impact, if any, future changes in environmental laws and regulations may have on the group s consolidated results or financial position.

Several of PacifiCorp s hydroelectric projects are in some stage of the FERC relicensing under the Federal Power Act. The relicensing process is a political and public regulatory process that involves sensitive resource issues. PacifiCorp cannot predict the requirements that may be imposed during the relicensing process, the economic impact of those

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requirements, whether new licences will ultimately be issued or whether PacifiCorp will be willing to meet the relicensing requirements to continue operating its hydroelectric projects.

UK regulations designed to restore, protect and enhance the quality of the environment are similarly introduced through a process of intensive and generally public consultation with the industry and other parties. The costs associated with the general tightening of environmental regulation may adversely affect UK turnover and profitability.

The group s business may be vulnerable to acts of terrorism.

Terrorism threats are an ongoing risk to the entire utility industry, including ScottishPower. Potential disruptions to operations and information technologies or destruction of facilities from terrorism, including cyber attacks, are not readily determinable and could lead to a loss of revenue and reduction in profitability.

The group s pension plan funding obligations are significant and are affected by factors beyond its direct control.

Estimates of the amount and timing of future funding obligations for the group s pension plans are based on various assumptions including, among other things, the actual and projected market performance of the pension plan assets, future long-term corporate bond yields and statutory requirements. In the last year the relative improvement in equity markets has seen the plans asset values rise, however this has been offset by falling bond yields and, therefore, the liabilities have increased in value. The investment risk continues to be monitored by the company and the trustees, which is reflected in the gradual shift in asset allocation from equities to bonds with a target of 50% equities in the two closed UK plans. As a result of the recent conditions in the equity markets and low interest rates, the group anticipates that pension expense and cash contributions into the pension plans will increase in the near future. The ability to recover pension costs through regulated rates and market prices cannot be predicted with certainty.

The UK Government s energy policy could change, negatively affecting the context in which the group has established its UK business strategy.

In the UK, energy policy has been set out in a Government White Paper, published in February 2003, which emphasises a continuing intention to make maximum use of market-based mechanisms whilst seeking to reduce the use of carbon, boost energy-saving and maintain efforts to mitigate the impact of fuel costs on lower-income households. There is particular focus on the use of renewable energy sources and developing discussion of the network enhancements likely to be required for the increased use of both renewables and embedded generation. The White Paper has received broad consistent with European Union (EU) policy generally. However, as the policy outlined extends well into the future, it could be subject to change and amendment by future Governments.

3 Quantitative and Qualitative Disclosures about Market Risk

Market Rate Sensitive Instruments and Risk Management

The following discussion about the group s risk management activities includes forward-looking statements that involve risk and uncertainties. Actual results could differ materially from those projected in the forward-looking statements.

The Tables in Note 20 to the Group Accounts on pages 129 to 134 summarise the financial instruments, including derivative instruments and derivative commodity instruments, held by the group at 31 March 2005, which are sensitive to changes in interest rates, foreign exchange rates and commodity prices. The group uses interest rate swaps, forward foreign exchange contracts and other financially settled derivative instruments to manage the primary market exposures associated with the underlying assets, liabilities and committed transactions. Financially settled weather derivatives may be used from time to time to manage risk created by varying weather circumstances affecting commodity demand and operations. The group also uses commodity transactions and commodity derivatives (that can be settled financially or by delivery of the physical commodity) to further manage its commodity price and volumetric risks. These instruments are employed to reduce risk by creating offsetting financial positions or by directly hedging such commodity exposures.

Such physically or financially settled instruments (as above) held by the group match offsetting physical transactions and are not held for financial trading purposes. Exceptions to this exist in the group s competitive divisions (PPM Energy and the UK Division) where a limited and controlled number of transactions and derivatives may be held for proprietary trading or price discovery purposes. In addition, weather derivatives are not held for proprietary trading purposes. Subject to risk management controls, businesses may enter into financial transactions that are designed to reduce earnings volatility and improve the return on assets and are structured around the physical assets of the group. ScottishPower Energy Management (Agency) Limited is authorised by the UK Financial Services Authority to undertake investment activity in the energy markets as an Energy Market Participant.

Risk Management

Overview

endorsement across the UK political spectrum and appears to be largely

The principal financial risks faced by the group are energy price risk, energy volumetric risk (created by varying demand due to weather and economic circumstances and varying

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supply due to forced outages or other physical supply and logistics limitations), credit risk, interest rate risk, inflation rate risk, insurance risk, foreign exchange translation and transaction risk, liquidity risk and derivative risk. The Board has reviewed and agreed policies for managing each of these risks as summarised below. In order to mitigate the financial risks identified, the Board has endorsed the use of derivative financial instruments including swaps, both interest rate and cross-currency, swaptions, options, forward-rate agreements, financial and commodity forward contracts, commodity futures, commodity options and weather derivatives.

Energy Risk Management

Energy risk is governed globally (with oversight from the Executive Team) by the Group Energy Risk Committee (GERC), chaired by the Group Energy Risk Director with membership from the divisions and the independent corporate risk management team. The GERC defines, and the ScottishPower Board approves, the group risk management policies and limits as well as the UK and the US risk policies and limits. These policies and limits are designed to create consistent risk measurement, monitoring and management standards throughout the group. The monitoring and management of the level of exposure covered is handled by the businesses, with full oversight by a corporate risk management function, independent of the businesses, reporting to the Finance Director. The businesses with commodity exposure are authorised to manage this exposure using approved products, policies and limits. These businesses each report no less frequently than monthly to a local risk committee, as well as to the GERC.

Market exposures are quantified and controlled using a number of different risk measures. These include Value-at-Risk (VaR) methods for earnings volatility control. VaR is a measure of the potential financial loss on a price exposure position over a defined period to a given level of confidence. VaR computations for the group s energy commodity portfolios are based on a historical simulation technique. This technique utilises historical energy market forward price curve changes over a specified period to simulate potential forward price curve changes to estimate the potential unfavourable impact of price changes in the portfolio positions scheduled to settle within the forward 24 months. The quantification of market risk using VaR provides a consistent measure of risk across the group s continually changing portfolio. VaR represents an estimate of possible changes at a given level of confidence in fair value that would be measured on its portfolio assuming hypothetical movements in future market rates, and is not necessarily indicative of actual results that may occur. Future changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted estimates.

The group s VaR computations for its energy commodity portfolio utilise several key assumptions, including a 99% confidence level for the resultant price changes and a holding period of five business days. VaR represents an estimate of reasonably possible changes in fair value that would be measured on its portfolio assuming hypothetical movements in future market rates. VaR, while sensitive to changes in portfolio volume, does not account for commodity volume risk. The calculation includes short-term commodity transactions and commodity derivative instruments held for trading and balancing purposes, the expected resource and demand obligations from the group s long-term contracts, the expected generation levels from the group s generation assets and the expected retail and wholesale load levels. Optionality embedded within the group s bilateral contracts, generation assets and other derivative instruments with option characteristics within the energy portfolio are treated in the historical simulation of VaR as static expected or delta adjusted positions through the simulation process. Expected positions and option deltas are recalculated on a daily basis to determine the portfolio position changes due to changes in market prices.

Commodity price exposure is defined as the possibility that a change in market prices will alter the proceeds of sales or the costs of purchases through the life of the transaction. Commodity volume risk is defined as the possibility that a change in the supply of or demand for the commodity will create an unexpected imbalance and change the requirements for the commodity. Additional risk measures are being developed to quantify risks beyond the confidence intervals defined in the VaR methodology and determine volumetric risks in physical positions. We apply stress tests to reinforce our VaR conclusions and have introduced stochastic analysis to estimate the impact of risks on outcomes.

Energy Price and Volume Risk Management

UK Division

The New Electricity Trading Arrangements (NETA) were introduced in England & Wales on 27 March 2001, replacing the previous Pool mechanism for the sale and purchase of wholesale electricity in England & Wales. NETA provided for a bilateral wholesale market, with suppliers, traders and generators trading firm physical forward contracts for bulk electricity supply. In addition to transacting to directly manage our market price exposure in the England & Wales market, the UK Division also manages its price exposure arising from sales within the Scottish market by the use of forward contracts. On 1 April 2005, NETA was superseded by the British Energy Trading and Transmission Arrangements (BETTA), which combined the Scottish wholesale market with the wholesale market in England & Wales, thus creating a Great Britain-wide wholesale electricity market.

Following the introduction of BETTA, the balancing mechanism, operated from one hour ahead of real-time (gate closure) up to real-time by the National Grid Company, is now used to manage the entire Great Britain grid system on a

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second-by-second basis, as opposed to only the England & Wales grid under NETA. Market participants can participate actively in this market through the submission of bids and offers to vary their output as a generator or demand as a customer. The mechanism also provides for calculation and settlement of imbalance charges and revenues arising from the differences between parties contract positions and their actual physical energy flows.

The UK Division has procedures in place to minimise exposure to uncertain balancing mechanism prices, that is, the possibility that the UK Division will face high charges for shortfalls in physical energy or receive low revenues for surplus physical energy. These procedures involve the UK Division entering into bilateral contracts for the sale and purchase of energy across a range of time periods to minimise exposure to the balancing mechanism. In addition, the division s portfolio of flexible generating assets in England and Scotland can be used up to gate closure to minimise further this exposure and also to attract premium income from providing flexible electricity to the balancing mechanism. A proportion of the wind output from several UK Division-owned wind generation facilities located within the UK is dispatched directly as generated into the UK electricity distribution system; however exposure to imbalance charges for this volume is largely mitigated through persistence modelling of the site output up until gate closure.

The UK Division has also entered into longer-term (in excess of one year) arrangements to protect against longer-term volatility of electricity prices. The time periods covered by these longer-term arrangements are reviewed on a continuous basis to provide the desired level of price stability.

The UK Division also has procedures in place to minimise exposure to natural gas price variations. In a similar manner to our electricity price exposure management strategy, natural gas price risk is managed through a combination of longer-term contracts and shorter-term trading contracts with flexible delivery profiles, certain derivative financial instruments and through the use of flexibility within the division s portfolio of electricity generation and natural gas storage assets. The UK Division mitigates its exposure to coal price risk through the use of a combination of financial and physical contracts as well as currency hedges executed by the ScottishPower treasury function. Cover against volatile spot prices is built up on a rolling basis through the year and, at 31 March 2005, a significant proportion of the UK Division s exposure to electricity, natural gas and coal price variations for the period to 31 March 2007 have been mitigated. Following the commencement of the EU Emissions Trading Scheme (ETS) in January 2005 the UK Division has an exposure to the price of carbon allowances, in order to enable the maximum economic running of thermal generation plant. The UK Division also has procedures in place to minimise exposure to carbon emission allowance price variations. In a similar manner to our power and natural gas price exposure management strategy, carbon emission allowance price risk is managed through trading contracts with delivery within each individual year throughout Phase 1 of the ETS (2005 to 2007). The euro exposure arising as a result of managing this carbon price exposure is mitigated with currency hedges executed by the ScottishPower treasury function.

The UK Division measures the market risk in its energy portfolio daily utilising the VaR approach (described above), stress tests as well as other measurements of net position, and monitors its portfolio exposure to market risk in comparison to established thresholds. The UK Division also measures its open positions at price risk in terms of volumes at each significant delivery location for each forward time period.

As at 31 March 2005, the UK Division s estimated potential five-day unfavourable impact on fair value of the energy commodity portfolio over the next 24 months was £11.9 million, as measured by the VaR computations (described above), compared to £8.8 million as at 31 March 2004. The average daily VaR (five-day holding period) for the year ended 31 March 2005 was £8.0 million. The maximum and minimum VaR measured during the year ended 31 March 2005 were £12.8 million and £4.2 million, respectively. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted estimates.

PacifiCorp

PacifiCorp s market risk to commodity price change is primarily related to its natural gas and electricity purchases and sales arising principally from its electricity supply obligation in the US. As in the UK, this risk to price change is subject to fluctuations in weather, economic growth and generation resource availability which impacts supply and demand. For example, during the 2004/05 winter months, PacifiCorp experienced higher than average temperatures and lower than normal snow pack and rain levels, producing lower than normal hydro conditions. Risk limits are established to govern energy purchases and sales. Price risk is managed principally through the operation of its generation and transmission system in the western US and through its wholesale energy purchase and sales activities. Physically settled contracts are used to hedge PacifiCorp s excess or shortage of net electricity for future months. PacifiCorp has a forecast net balanced position for the summer of 2005.

While PacifiCorp plans for resources to meet its current and expected retail and wholesale load obligations, resource availability, price volatility and volumetric volatility around both load and resources may materially impact the net power costs to PacifiCorp and profits from surplus power sales in the future. Prices paid by PacifiCorp to provide certain load balancing resources to supply its load may exceed the amounts it receives through retail rates and wholesale prices. Prices received by PacifiCorp to dispose of resources made excess by

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Risk Factors

changes in retail and wholesale load obligations may fall short of the amounts PacifiCorp has paid for such resources. In the 2000/01 power crisis, regulatory approval of deferred accounting treatment under US GAAP for these excess costs mitigated a portion of this price risk to the extent that recovery mechanisms were implemented. Recovery of amounts allowed by the public utility commissions are scheduled to continue through 2005. Deferred accounting treatment was granted to allow PacifiCorp to recover a portion of the excess power costs from the power crisis. Subsequent use of this mechanism is not automatic and is not guaranteed for future use.

PacifiCorp continues to actively manage commodity price volatility and reduce exposure. These steps include adding to its generation portfolio and entering into transactions that help to shape PacifiCorp s system resource portfolio, including wholesale contracts and financially settled temperature-related derivative instruments that reduce volume and price risk due to weather extremes. In addition, a streamflow hedge is in place through September 2006 to reduce volume and price risks associated with PacifiCorp s hydroelectric generation resources.

PacifiCorp measures the market risk in its natural gas and electricity portfolio daily utilising the VaR approach (described above), as well as other measurements of net position, and monitors its portfolio exposure to market risk in comparison to established thresholds. PacifiCorp also measures the price risk of its open positions in terms of quantity at each significant delivery location for each forward time period.

At 31 March 2005, PacifiCorp s estimated potential five-day unfavourable impact on fair value of the natural gas and electricity commodity portfolio over the next 24 months was £9.7 million, as measured by the VaR computations (described above), compared to £10.0 million at 31 March 2004. The average daily VaR (five-day holding) for the year ended 31 March 2005 was £10.4 million. The maximum and minimum VaR measured during the year ended 31 March 2005 were £16.4 million and £6.6 million, respectively. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted estimates.

PPM Energy

PPM Energy is ScottishPower s competitive US energy business, which is primarily focused on providing environmentally responsible energy products to wholesale customers. The strategic priorities of PPM Energy are to grow its renewable/thermal energy portfolio and natural gas storage/hub services business and optimise returns through the integration of assets, trading and commercial activities. PPM Energy s strategy is to match the capacity and output of PPM Energy assets and long-term sales obligations. Imbalances between asset positions and long-term sales are managed via wholesale energy purchases and sales activities.

number of other facilities. Associated with the wind energy production are Renewable Energy Certificates (RECs) that represent the environmental attributes of the renewable energy. Consistent with its overall portfolio strategy, PPM Energy balances its wind asset position with long-term forward sales and some spot sales of both energy and renewable attributes. Wind generation resource availability and variability is subject to price changes for that portion of the output that is not committed to long-term fixed price bilateral contracts. Imbalances in the REC portfolio are subject to price changes in the REC market.

PPM Energy owns or controls over 800 MW of thermal capacity on its own behalf and on the behalf of third parties. Substantially all of this capacity is committed to long-term contracts, with the imbalance being subject to generation resource availability and the relationship of fuel (natural gas) costs to electricity prices (or spark spread). PPM Energy manages short-term and daily imbalance through real-time markets. PPM Energy s risk in this business is principally if counterparties fail to perform in accordance with contracts and if PPM Energy s generation assets fail to perform at reasonable levels.

PPM Energy also owns and manages group owned natural gas storage facilities and contracted natural gas storage capacity in Canada, Texas, New Mexico and other locations. PPM Energy s strategy is to develop a natural gas storage/hub services business that will own and operate facilities across North America. Through a process of prudent risk limits, established risk information systems and clear reporting, PPM Energy s gas storage business model is designed to minimise commodity risk. PPM Energy provides a service for a fee for both long-term and short-term hub services. Hub services is a generic term used to describe various fee-based transactions carried out by the storage operator such as parking and loaning of natural gas or the wheeling of natural gas from one pipeline to another at the storage location. As a result, the hub services business is subject to the risks associated with the operations and marketing of the storage facilities and services.

PPM Energy may maintain or create open positions in response to (or in anticipation of) long-term origination or development transactions creating exposure to market price movements, subject to market risk limitations delegated by ScottishPower and oversight by the corporate risk management group embedded in PPM Energy. As such, PPM Energy will participate in the wholesale electricity and natural gas markets to manage its open positions. In addition, PPM Energy engages in point-of-view energy management activities in accordance with strict limits approved by the business unit risk committee (chaired by the group risk management function). Control and performance metrics for such activities are tracked daily.

PPM Energy measures the market risk in its natural gas and electricity portfolio daily utilising the VaR approach (described above), as well as other measurements of net position, and monitors its portfolio exposure to market risk in

PPM Energy owns a number of wind generation facilities located throughout the US and also owns the output from a comparison to established thresholds. PPM Energy also measures its open positions at price risk in terms of volumes at each delivery location for each forward time period.

At 31 March 2005, PPM Energy s estimated potential five-day unfavourable impact on fair value of the energy commodity portfolio over the next 24 months was £8.9 million, as measured by the VaR computations (described above), compared to £5.8 million at 31 March 2004. The average daily VaR (five-day holding) for the year ended 31 March 2005 was £5.4 million. The maximum and minimum VaR measured during the year ended 31 March 2005 were £8.9 million and £1.2 million, respectively. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted estimates.

Credit Risk Management

The role of the group s credit function, which is part of the independent corporate risk management group, is to set consistent standards for assessing, quantifying, monitoring, mitigating and controlling the credit risk introduced by contractual obligations of wholesale trading partners, suppliers and industrial and commercial customers. A group credit committee provides umbrella oversight to ensure a consistent approach to counterparty rating. The group credit committee manages credit limits adopted across the group and oversees the allocation of limits to those counterparties that overlap both the US and the UK markets. This group credit committee ensures that each individual business is subject to concentration rules that prevent misallocation of credit risk amongst counterparties. Beneath the group credit committee, the UK and the US credit committees provide local expertise to understand the credit environment in each geographic location. All decisions are supported by rigorous measurement and reporting of credit exposures and the use of credit rating models. Credit approvals are subject to regular and/or event driven reviews.

To be eligible for a credit line, which is a function of credit quality, counterparties for energy commodity transactions must meet the following requirements: (a) counterparties must be determined investment grade by an internal process review or through an external assessment process (rated BBB- or better by Standard & Poor s Ratings Group (S&P) or equivalent rating from Moody s Investors Service (Moody s)) to avoid posting collateral or otherwise perfect their credit, or (b) non-rated or less than BBB- rated counterparties must either have a guarantee from an investment grade entity, post collateral or provide other assurances deemed acceptable to the group credit committee.

Treasury Risk Management

The group treasury function is authorised to conduct the day-to-day treasury activities of the group within policies set out by the Board. The group treasury function reports regularly to the Board, through the monthly Group Performance and Risk Report and is subject to internal audit.

Interest Rate Risk Management

The group continues to manage its interest rate exposure by maintaining a percentage of its debt at fixed rates of interest. This is done either directly by means of fixed rate debt issues or by use of interest and cross-currency swaps to convert variable rate debt into fixed rate debt and fixed/variable non-functional currency denominated debt into fixed rate functional currency debt. The use of derivative financial instruments relates directly to underlying existing and anticipated indebtedness.

The exposure to fluctuating interest rates is managed by either issuing fixed or floating rate debt or using a range of financial derivative instruments to create the desired fixed/floating mix. The group s interest rate policy is to target a long-term benchmark of at least 70% fixed rate interest. At 31 March 2005, 98% (March 2004: 84%) of the net debt was either issued as fixed or converted to fixed rates using interest rate swaps. The weighted average period to maturity of year end fixed debt and interest swaps was 10 years (UK 10 years, US 10 years). Based on net floating rate investments of £134 million at 31 March 2005, a 1% change in interest rates at that date would result in a £1.3 million change in profit before tax over a twelve-month period.

All treasury transactions are undertaken to manage the risks arising from underlying activities and no speculative trading is undertaken. The counterparties to these instruments generally consist of financial institutions and other bodies rated at least AA- by one of S&P, Moody s or The Fitch Group. Although the group is potentially exposed to credit risk in the event of non-performance by counterparties, such credit risk is controlled through credit rating reviews of the counterparties and by limiting the total amount of exposure to any one party to levels agreed by the Board. The group does not believe that it is over exposed to any material concentration of credit risk.

Inflation Rate Risk Management

In recognition of the fact that a portion of UK revenues are linked to inflation, Scottish Power UK plc maintains part of its debt portfolio in index-linked liabilities. This is done either through issues of debt or through swapping fixed rate debt into index-linked. Index-linked liabilities total £275 million, which represents around 8% of the UK debt portfolio.

Insurance Risk Management

Where cost effective, the group maintains a wide-ranging insurance programme providing financial protection, predominately against catastrophic risks. The insurance market has continued to show mixed trends in pricing over the past year. For property insurance, there has been a general decrease in premiums although the extent of the decrease has shown signs of levelling off. Other classes of insurance are still experiencing upward pressure on premiums. The group has worked closely with its insurance advisors and insurers to maintain efficiencies and long-term stability in premium costs.

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Risk Factors

The renewal of the group s main insurance policies for 2005/06 has been completed with commercial insurers delivering a net premium reduction.

Foreign Exchange Risk Management

Translation Risk

The principal objective of our currency risk management and hedging strategy is to seek to mitigate exposure to movements in foreign exchange rates for both dollar denominated net assets and earnings, taking into account its potential effect on our net debt and related credit statistics. The aim is to hedge nearly 100% of US net assets with dollar liabilities. This is done by a combination of borrowing dollars in the UK, swapping sterling debt into dollars or creating additional dollar liabilities (and corresponding sterling assets) to the extent that total net dollar assets exceed UK based debt. The resulting stream of dollar interest acts as a natural partial hedge to the translation of US profits. US profits are greater than interest paid in dollars and the resulting gap is hedged either by UK based purchases of coal (which is traded in dollars) or by selling dollars in order to mitigate the impact of exchange rate movements. Under International Financial Reporting Standards, International Accounting Standard 39 Financial Instruments: Recognition and Measurement prohibits the hedging of internal cash flows, and therefore the group s previous strategy under UK GAAP of hedging expected US dollar profits using US dollar forwards will no longer be permitted. Subject to EU approval, transitional provisions will however, enable the group to use dollar forwards for earnings hedge purposes for financial year 2005/06. However, this will cease with effect from 1 April 2006. All foreign currency derivative contracts are subject to the same controls as interest rate derivatives referred to above.

Any foreign currency denominated debt will be subject to re-translation at period end closing rates. A ten cent (5%) strengthening of the 31 March 2005 closing US dollar exchange rate would give rise to a £188 million increase in reported net debt at 31 March 2005.

Transaction Risk

Other than the import of coal and trading of carbon allowances in the UK, transactions denominated in a foreign currency are not numerous in the group. Where they arise as a result of imports of capital or other goods denominated in foreign currencies the exposure is hedged as soon as it is committed.

group has entered into borrowing agreements for periods out to 2039. The weighted average period to maturity of year end debt was ten years. The group had undrawn committed revolving credit facilities totalling $1,800 million as at 31 March 2005 which provide backstop liquidity should the need arise. Liquidity in the UK is currently supported by proceeds from the $1,500 million bond issue and cash receipts from matured and cancelled cross-currency swaps. Current cash investments amount to £1,748 million.

Derivative Risk Management

The use of derivative financial instruments (other than those described for energy commodities above) relates directly to underlying existing and anticipated indebtedness, foreign subsidiary earnings and net assets and business transactions denominated in foreign currencies.

During the year, several cross-currency swaps and foreign exchange forwards hedging the US dollar net assets matured, resulting in cash receipts of £140 million and were replaced with new cross-currency swaps with maturities between 2007 and 2010. As well as this, $1,500 million of cross-currency swaps were cancelled in conjunction with the $1,500 million bond issue by Scottish Power plc which replaced the swaps as a hedge of the US dollar net assets and resulted in cash receipts of £92 million. These cash receipts resulted from the weakness of the US dollar since the hedges were put in place. A prolonged period of relative US dollar strength would result in the payment of cash to counterparties, to the extent that the derivatives had not been replaced by primary dollar debt.

Credit risk on non-energy commodity derivative transactions is mitigated by a policy of only using counterparties with a credit rating of AA- or above. Exposure to derivative counterparties is monitored using measures, dependent on the type of transactions, that take into account potential market volatility.

Liquidity Risk Management

In recognition of the long life of the group s assets and anticipated indebtedness, and to create financial efficiencies, the group s policy is to arrange that debt maturities are spread over a wide range of dates, thereby ensuring that the group is not subject to excessive refinancing risk in any one year. The

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Board of Directors

and Executive Team

Chairman

Charles Miller Smith (65) joined the Board as Deputy Chairman in August 1999 and was appointed Chairman in April 2000. Following a career with Unilever for some 30 years, during the last five of which he was Director of Finance and latterly of the Food Executive, he was appointed Chief Executive of ICI in 1995 and then served as Chairman from 1999 to 2001. He is a member of the Board of the Indian company, ICICI One Source plc, and of the Ministry of Defence Management Board. During the year, he participated in a programme mentoring women in senior business roles with a view to increasing female representation in the boardroom.

Non-Executive Directors

Vicky Bailey (53) joined the Board in June 2004. Based in Washington DC, she is a former Assistant Secretary for Policy and International Affairs at the US Department of Energy and ex-member of the Federal Energy Regulatory Commission (FERC). She has also served as an Indiana state utility regulator, and was President of PSI Energy Inc., Indiana s largest electricity supplier, from June 2000 to July 2001. She is currently a Partner of Johnston & Associates, a public and legislative affairs consultancy. Her current term of office, following her election in 2004, will expire at the AGM in 2007.

Euan Baird (67) joined the Board in January 2001. He served as Chairman and Chief Executive Officer of Schlumberger Limited from 1986 to 2003, and as non-executive Chairman of Rolls-Royce plc until June 2004. He is a non-executive director of Société Générale and Areva. He is a trustee of Tocqueville Alexis Trust and Carnegie Institution of Washington. His current term of office will expire at the AGM in 2007.

Donald Brydon (59) joined the Board in May 2003. Following a 20-year career with Barclays Group plc, he joined AXA Group in 1997 and is now Chairman of AXA Investment Managers. He is also Chairman of Smiths Group plc and the London Metal Exchange, and Chairman of the Code Committee of the Panel on Takeovers and Mergers. His current term of

Corporation, a California-based international engineering, construction and services company, until his retirement in February 2002. Previously, he was with Shell Oil for over 35 years, serving as President and Chief Executive Officer from 1993 to 1998. He is an honorary life member of the Board of the American Petroleum Institute and holds various posts with the James A Baker III Institute for Public Policy of Rice University and the University of Houston. He will retire from the Board after the AGM in 2005.

Nolan Karras (60) joined the Board in November 1999. He continues as a non-executive director of PacifiCorp, having previously (until the merger in November 1999) served as Chairman of the PacifiCorp Personnel Committee. He is Chair of the PacifiCorp Utah regional advisory board, and President of The Karras Company, Inc., and a Registered Principal for Raymond James Financial Services. He is Chief Executive Officer of Western Hay Company, Inc., and a non-executive director of Beneficial Life Insurance Company. He is Chairman of the Utah State Higher Education Board of Regents and a member of the board of Ogden-Weber Applied Technology College. He also served as a member of the Utah House of Representatives from 1981 to 1990, and as Speaker of the Utah House of Representatives from 1989 to 1990. His current term of office, subject to his re-election in 2005, will expire at the AGM in 2006.

Nick Rose (47) joined the Board in February 2003. He is Chairman of the Audit Committee and is the Committee s designated financial expert . He is Finance Director of Diageo plc, having been appointed to this position in July 1999. Previously he held senior finance positions with GrandMet and was latterly Finance Director of International Distillers & Vintners in 1996 and then of United Distillers & Vintners in 1997. He is also a director of Moët Hennessy. His current term of office will expire at the AGM in 2006.

Nancy Wilgenbusch (57) joined the Board in June 2004. She is a distinguished community administrator and President of Marylhurst University in Portland, Oregon. She served as a non-executive director of PacifiCorp from 1986 until the merger in November 1999 and is Chair of the PacifiCorp Pacific regional advisory board. She is a former office, subject to his re-election in 2005, will expire at the AGM in 2006.

Philip Carroll (67) joined the Board in January 2002, but was absent during the period May to October 2003. He was formerly Chairman and Chief Executive Officer of Fluor

chair of the Portland Branch of the San Francisco Federal Reserve, and a director of West Coast Bank. Her current term of office, following her election in 2004, will expire at the AGM in 2007.

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Board of Directors and Executive Team

Executive Directors

Ian Russell (52) is Chief Executive, having been appointed to this position in April 2001. He joined ScottishPower as Finance Director in April 1994, and became Deputy Chief Executive in November 1998. He is a member of the Institute of Chartered Accountants of Scotland, having trained with Thomson McLintock, and has held senior finance positions with HSBC. He serves on the Council of Edinburgh International Festival and the Scottish Council of the Prince s Trust. During the year he led a UK Government Commission on the development of a National Youth Volunteering Strategy, the conclusions of which were published in March 2005.

David Nish (45) is Finance Director, having joined ScottishPower in September 1997 as Deputy Finance Director and then being appointed to the Board as Finance Director in December 1999. In this capacity, he also has responsibility at Board level for performance and risk management. He is a member of the Institute of Chartered Accountants of Scotland, the Scottish Council of the CBI, and the Accounting Standards Board s Urgent Issues Task Force, and a non-executive director of The Royal Scottish National Orchestra. Prior to joining ScottishPower, he was a partner with Price Waterhouse. He has a BAcc from the University of Glasgow. As previously announced he becomes Executive Director, Infrastructure as part of the planned board development programme with effect from 24 May 2005.

Charles Berry (53) is Executive Director UK, responsible in this capacity for the UK energy businesses of Generation, Energy Management and Supply. He joined ScottishPower in November 1991 and was appointed to the Board in April 1999. He is a non-executive director of the Securities Trust of Scotland plc. Prior to joining ScottishPower, he was Group Development Director of Norwest Holst, a subsidiary of Compagnie Générale des Eaux, and prior to that held management positions within subsidiaries of Pilkington plc. He holds a BSc (First Class Hons) in Electrical Engineering from the University of Glasgow and a Masters Degree in Management from the Massachusetts Institute of Technology.

Judi Johansen (46) is President and Chief Executive Officer of PacifiCorp; she was appointed to this position in June 2001 and joined the Board on 1 October 2003. She joined PacifiCorp as Executive Vice President of Regulation and External Affairs in December 2000, having held senior positions with the Bonneville Power Administration and Washington Water Power. She is a former member of the Board of the Portland Branch of the US Federal Reserve Bank of San Francisco, a Lewis & Clark College. She has a bachelor s degree in political science from Colorado State University and a law degree from Northwestern School of Law at Lewis & Clark College in Portland, Oregon, and is a member of the Oregon and Washington State Bar Associations.

Simon Lowth (43) is Director, Corporate Strategy and Development, having been appointed to the Board in this position on 1 September 2003. He is responsible in this role for leading the formulation, presentation and delivery of corporate strategy. With effect from 24 May 2005 he assumes the new role of Executive Director, Finance and Strategy. He was formerly a Director with McKinsey and Company, leading its UK industrial practice, serving clients in the energy and utilities, manufacturing and transport sectors. He holds an MA in Engineering from Cambridge University and an MBA from London Business School.

Executive Team

The Executive Team is constituted as a committee of the Board and includes not only the Executive Directors of the Board but also the following key Executives and Officers from the group. For US reporting purposes the members of the Executive Team, and also the Company Secretary, are regarded as officers of the company.

Dominic Fry (45) joined ScottishPower in September 2000 as Group Director, Corporate Communications. He is responsible for investor and media relations, communications with employees, corporate social responsibility and management of the group s overall reputation. He has held appointments as Communications Director with J Sainsbury plc and Eurotunnel plc. He chairs the Trading Board of the Glasgow Science Centre and is a communications adviser to the Royal Shakespeare Company and Business in the Community. He is also a director of Scottish Business in the Community and of Project Scotland. He was educated at the Université Paul Valéry III in Montpellier and the University of North Carolina.

Terry Hudgens (50) was appointed Chief Executive Officer of ScottishPower s competitive US energy business, PPM Energy, in commissioner for the Port of Portland, director of the Oregon Business Council and trustee of law at

May 2001 and joined the Executive Team in December 2001. He joined PacifiCorp as Senior Vice President of Power Supply in April 2000, having previously spent 25 years with Texaco, Inc. He was formerly President of Texaco Natural Gas and served as Texaco s senior representative and elected officer in the Natural Gas Supply Association. He is a member of the Board of Trustees of The Nature Conservancy in Oregon. He has a bachelor s degree in civil engineering from the University of Houston.

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Ronnie Mercer (61) is Executive Vice President, Operations, PacifiCorp, having been appointed to this new role on 1 January 2005. In this role he has joint responsibility with Judi Johansen for the operating performance and results within Generation, Power Delivery and Mining. He was previously Group Director, Infrastructure and was responsible for the UK wires businesses. He joined the ScottishPower Generation Business in 1994 and was appointed Generation Director in 1996 and then Managing Director of Southern Water in 1998. Previous career positions include Scottish Director and Managing Director roles in British Steel. He was educated at Paisley College of Technology.

Michael Pittman (52) was appointed Group Director, Human Resources in November 2001. He has groupwide responsibility for human resources, leading the focus on talent management, one of the group s main strategic thrusts. He joined PacifiCorp in December 1979 and was appointed to the PacifiCorp Board in May 2000. He chairs the PacifiCorp Foundation for Learning Board and is involved in numerous civic activities, including chairing the Board of Directors for the Oregon Public Employees Retirement System. He has held several positions within PacifiCorp, including safety and health, risk management and operations. He holds an advanced degree in environmental health from the University of Washington.

James Stanley (50) is Legal, Commercial and Compliance Director, having joined ScottishPower in March 1996. He is responsible for legal compliance and reporting together with the provision of all legal, commercial and associated services and particularly the negotiation, structuring and delivery of M&A and similar projects. In January 2005 his role was expanded to include responsibility for the Corporate Secretarial Department and the coordination of procurement throughout the group. In his early career he specialised in commercial litigation in private practice. In 1986 he moved to the Trafalgar House Group and subsequently became both Commercial Director of John Brown plc and General Counsel to the Global Engineering Division of the Group. He is a graduate in law from Nottingham University and the College of Law in Chester where he qualified as a solicitor in 1980.

David Rutherford (41) is Managing Director, PowerSystems, having been appointed to that role in April 2003. He holds a BSc in Electrical and Electronic Engineering from Strathclyde University and an MBA from Heriot Watt University. During the period between Ronnie Mercer s appointment as Executive Vice President, Operations at PacifiCorp and David Nish becoming Executive Director, Infrastructure in May 2005, he acted as Divisional Director, Infrastructure and in that capacity attended Executive Team meetings.

Company Secretary

Andrew Mitchell (53) was appointed Group Company Secretary in July 1993 and is responsible in this role for Board and shareholder services, corporate governance and compliance, and group security. He also serves as Chairman of the trustees of the group s UK pension schemes and as the company s e7 representative. Prior to joining ScottishPower, he held a number of company secretarial appointments, latterly as Company Secretary of The Laird Group plc and then Stakis plc, now part of the Hilton Group. He is a graduate in law from the University of Edinburgh (LLB Hons) and the London School of Economics (LLM) and is a member of the Institute of Chartered Secretaries and Administrators.

Members of the Nomination Committee

Charles Miller Smith, Chairman

Donald Brydon

Nolan Karras

Ian Russell

Nancy Wilgenbusch

Members of the Remuneration Committee

Nolan Karras, Chairman

Euan Baird

Donald Brydon

Philip Carroll

Nick Rose

Nancy Wilgenbusch

Members of the Audit Committee

Nick Rose, Chairman

Vicky Bailey

Donald Brydon

Philip Carroll

Nolan Karras

Board and Executive Team changes

Mair Barnes and Sir Peter Gregson retired from the Board following the conclusion of last year s AGM on 23 July 2004. Vicky Bailey and Nancy Wilgenbusch were appointed to the Board on 1 June 2004; their appointments were confirmed by election at the AGM in 2004.

In accordance with the Articles of Association, Charles Berry, Donald Brydon, Philip Carroll and Nolan Karras will retire from office at the Annual General Meeting. Charles Berry, Donald Brydon and Nolan Karras, being eligible, offer themselves for re-election. Philip Carroll will retire from the Board and accordingly does not seek re-election. Charles Berry has a service contract terminable by either party upon 12 months notice.

Changes to the responsibilities of Executive Team members are described in their individual biographies.

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Corporate Governance

Dear Shareholder,

I am pleased to introduce this section of the Annual Report which sets out our company s approach to corporate governance. Corporate governance is a term which is frequently used but often misunderstood, so to be clear about what we mean by it: we see corporate governance as being about the relationship between the company, its directors and its shareholders. Corporate governance determines how authority and accountability are distributed throughout the company and sets the framework within which we meet our objectives. All of the members of the Board recognise that as directors we are in a position of trust; as such, we believe we have a responsibility to our shareholders to put in place robust structures and processes and to observe the highest standards of corporate governance.

We have made a number of changes to our corporate governance arrangements over the past couple of years. These have reflected developments in best practice, most notably contained in the Higgs Report and the resultant revised Combined Code in the UK as well as the Sarbanes-Oxley Act of 2002 in the US. The changes we have made have not, however, been driven simply by a desire to achieve compliance; rather, we have made changes because we recognise them to be pragmatic and worthwhile improvements. In particular, we have placed an emphasis on the professionalism of the Board, employing external performance evaluation and a structured programme of directors induction and training.

I hope you find the statement which follows both interesting and informative. We are committed to maintaining an open and constructive dialogue on corporate governance issues, and I would welcome any suggestions or comments you may have.

Charles Miller Smith Chairman

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1 Corporate Governance Statement

Scottish Power plc is committed to the highest standards of corporate governance. This statement, together with the Remuneration Report of the Directors (set out on pages 95 to 105), describes how the company has applied the principles of good corporate governance set out in Section 1 of the Combined Code in the UK and has complied with the Sarbanes-Oxley Act of 2002 and associated rules (to the extent they currently apply to the company) in the US. In respect of the financial year ended 31 March 2005, the company has complied fully with the provisions set out in Section 1 of the Combined Code, except in one respect arising from Code provision D.1.1 which is concerned with dialogue with major shareholders on issues of governance and strategy. An explanation of this is contained in the statement below under the heading Relations with Shareholders.

The company has taken account of the corporate governance rules contained in the listing rules of the New York Stock Exchange (as they apply to foreign issuers) and a summary of the differences between those rules and the company s practices is contained in the statement below.

2 Board Composition

The Board comprises the Chairman, five executive directors and seven non-executive directors. The Chairman is Charles Miller Smith, the Chief Executive is Ian Russell and Donald Brydon is the senior independent director. The chairmen and members of the Nomination, Remuneration and Audit Committees are listed on page 83 and in the reports from the respective Committees. Details of the attendance of Board members at meetings of the Board and its Committees are set out in Table 46.

There is a clear division of authority at the most senior level within the company through the separation of the roles of Chairman and Chief Executive. This ensures that no one individual has unfettered powers of decision. The division of responsibilities between the role of the Chairman to run the Board and the role of the Chief Executive to run the company s business is documented in writing and has been agreed by the Board.

The senior independent director serves on the Nomination, Remuneration and Audit Committees and is the presiding director at meetings of the non-executive directors. He is responsible for providing feedback to the Chairman following the evaluation (conducted by all directors) of the performance of the Chairman. He is also available to shareholders for concerns which have not been resolved by contact with the Chairman or Chief Executive or for which such contact is inappropriate.

Biographies of Board members, giving details of their experience and other main commitments, are set out on pages 81 and 82. Any changes to the other commitments of the directors are reported to the Board and the company s position on executive directors undertaking external non-executive appointments is set out on page 100 of the Remuneration Report. The diverse experience and backgrounds of the non-executive directors ensures that they can debate with and constructively challenge management both in relation to the development of strategy and in relation to operational and financial performance.

All of the non-executive directors are considered by the Board to be independent in character and judgement, having no material relationship with the company. The decision of the Board to make this determination was informed by questionnaires completed at the year-end by all non-executive directors, based on the independence tests contained in the Combined Code, the corporate governance rules contained in the listing rules of the New York Stock Exchange and the tests for the independence of audit committee members contained in rules promulgated by the US Securities and Exchange Commission.

Nolan Karras and Nancy Wilgenbusch served as directors of PacifiCorp from 1993 and 1986 respectively until the merger in 1999; Mr Karras joined the Scottish Power plc Board immediately on the merger while Dr Wilgenbusch joined the Board in 2004. Mr Karras remains a director of PacifiCorp (but receives no additional fee for this service) and is chair of the PacifiCorp Utah regional advisory board. Dr Wilgenbusch serves as chair of the PacifiCorp Pacific regional advisory board. Both directors receive emoluments in the US for their service on the regional advisory boards as detailed in the Remuneration Report. The regional advisory boards link the company with the communities it serves in the US and enable it to maintain constructive relationships with key stakeholder groups.

In assessing independence, the Board considered that service on the PacifiCorp board prior to the merger date should be disregarded on account of a new company, with a substantially refreshed board, having been formed. The Board considered that the emoluments for service on the respective advisory boards constituted fees paid for service on a committee of the PacifiCorp board (as PacifiCorp is an affiliate of the company, these fees qualify for an exemption contained in rules, relating to independence standards for audit committee members, promulgated under the US Securities Exchange Act of 1934). The Board considered that their payment does not in any way compromise the independence of the directors. Accordingly, the Board concluded that all of the non-executive directors are independent and that therefore it meets the Combined Code requirement that at least half the board, excluding the chairman, should comprise independent non-executive directors.

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Corporate Governance

Non-executive directors are appointed for a specified term of three years and re-appointment is not automatic. It is company policy that, other than in exceptional circumstances, non-executive directors should serve no more than two three-year terms. Directors also stand for re-election by the shareholders at the first annual general meeting following their appointment and at regular intervals of not more than three years thereafter. Decisions on re-election are informed by the results of the performance evaluation of the director concerned. The report from the Nomination Committee below explains the process for selection of directors and sets out the Committee s responsibility for reviewing the composition of the Board and for succession planning. The Committee kept the composition of the Board under review throughout the year, considering the size and diversity of the Board in terms of its gender, age and nationality profile as well as the skills, experience and connections of individual directors.

`Directors and officers of the company and its subsidiaries have the benefit of a directors and officers liability insurance policy which provides appropriate cover in respect of legal action brought against its directors. Article 159 of the company s Articles of Association provides that every director or officer of the company shall be entitled to be indemnified by the company to the extent permissible under UK company law in respect of liabilities incurred in connection with their duties, powers or office. The Board has approved the granting of deeds of indemnity (in similar terms to Article 159) to each current director and officer of the company. Once granted, these indemnities will be available for inspection by shareholders at the company s registered office. In addition, all directors have access to the advice and services of the Company Secretary and can take independent professional advice at the company s expense in the furtherance of their duties.

3 Board Proceedings

During the year, the Board planned to hold 12 monthly meetings, six at locations in the UK and US and the remaining six by telephone conference, with additional meetings being arranged as required. As an outcome of the Board performance evaluation conducted in 2004, the Board meeting programme was reviewed during the year in an effort to make best use of directors time.

For a number of years, the company has provided an opportunity within the scheduled meeting programme for the non-executive directors to meet on occasion without the Chairman or executive directors present. The meeting is structured so that the Chairman and Chief Executive are in attendance for the first part of the meeting. The Chief Executive then retires, leaving the Chairman to continue the meeting with the non-executive directors. Similarly, after an appropriate time, the Chairman leaves the meeting, with the non-executive directors continuing the discussion alone (under

Table 46

Ø Board and Committee attendance during the year ended 31 March 2005

	Charles Miller Smith (N*)	Vicky Bailey[2] (A)	Euan Baird[3] (R)	Mair Barnes[4] (N, R)	Donald Brydon[5] (N, R, A)	Philip Carroll (R, A)	Sir Peter Gregson[6] (N, R, A)	Nolan Karras (N, R*, A)	Nick Rose[7] (R, A*)	Nancy Wilgenbusch[8] (N, R)	Ian Russell (N)	Charles Berry	Judi Johansen	Simon Lowth	David Nish
Board (11 meetings[1])	11	8	1	4	10	10	4	11	7	9	11	11	11	11	11
Nomination Committee (4 meetings)	4			1	3		1	4		3	4				
Remuneration Committee (2 meetings)			0	1	2	2	1	2	0	1					
Audit Committee															

(6 meetings)	3	6	6	3	5	5

N Nomination Committee

R Remuneration Committee

A Audit Committee

* Committee Chairman

[1] While the Board planned to hold 12 monthly meetings, a change in the timing of the meetings during the period meant that 11 scheduled meetings were held, with the final meeting for the year actually taking place in early April 2005.

[2] Vicky Bailey was appointed to the Board, and to the Audit Committee, in June 2004.

[3] Euan Baird was absent from the Board and Remuneration Committee due to ill health for the duration of the year until January 2005.

[4] Mair Barnes retired from the Board, and from the Nomination and Remuneration Committees, in July 2004.

[5] Donald Brydon was appointed to the Nomination Committee in June 2004.

[6] Sir Peter Gregson retired from the Board, and from the Nomination, Remuneration and Audit Committees, in July 2004.

[7] Nick Rose was appointed to the Remuneration Committee in June 2004.

[8] Nancy Wilgenbusch was appointed to the Board, and to the Nomination and Remuneration Committees, in June 2004.

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the guidance of the senior independent director). In the 2004/05 financial year, a meeting was held in April 2004 but the meeting planned for October 2004 was cancelled due to prevailing circumstances. A further meeting was held in early April 2005, and one of the main purposes of this was to coincide with the conclusion in 2004/05 of the process of Board performance evaluation.

The Board adopted the current schedule of matters reserved to it for decision in January 2004. This schedule is intended to ensure that the Board retains full control over strategy, investment and capital expenditure, and limits the decisions which can be taken by management in the areas of governance, strategic and financial management and reporting, capital structure, corporate actions, mergers and acquisitions, energy management, contracts and other commitments, litigation and regulatory proceedings, and remuneration and share plans. Where authority is delegated to management, it is on a structured basis according to a delegation of authority matrix (based on the schedule of matters reserved to the Board), ensuring that proper oversight and accountability exist at the appropriate level. Within management, the Executive Team, which meets at least once a month either physically or by telephone conference, ensures executive focus on groupwide performance and risk management, while each of the four businesses (PacifiCorp, Infrastructure Division, UK Division and PPM Energy) holds monthly board meetings involving the Chief Executive and Finance Director as well as senior divisional management.

Board meetings involve reviews of financial and business performance against the plan approved by the Board and risk management, both at a group level and also for each of the four businesses, on a month-by-month basis. They also cover strategic issues, business issues requiring decision (often in relation to capital expenditure projects) and other specific issues for decision or information. On a rotating basis, the Board receives presentations from each of the businesses and other key functions, enabling it to explore specific issues and developments in more detail. Any matter requiring a decision by the Board will be supported by a paper analysing relevant aspects of the proposal for example, in the case of capital expenditure, the expected returns and a comparison with the investment hurdles set by the Board, as well as potential risks and proposed management action.

The Company Secretary is responsible for ensuring that Board procedures are observed and for advising the Board on all corporate governance matters. The Company Secretary s remit also encompasses ensuring good information flows within the Board and its Committees as well as facilitating the programme of directors induction and professional development and the Board performance evaluation exercise. The appointment and removal of the Company Secretary is reserved to the Board for its decision.

The Board is supported by a number of committees: as well as the Nomination, Remuneration and Audit Committees, the Board has also established a Group Finance Committee, chaired by Philip Carroll and comprising both executive and non-executive directors, which allows for more detailed scrutiny of financing issues than would be possible within the confines of regular Board meetings. It has authority to approve financing transactions within the strategy set by the Board. Reports from the Nomination and Audit Committees are contained in the statement below. The activities of the Remuneration Committee are described in the Remuneration Report on pages 95 to 105.

4 Directors Induction and Professional Development

All newly appointed directors receive a full and structured induction to ensure they have the necessary knowledge and understanding of the company and its activities. The induction programme takes into account each director s particular background and experience in order to develop a plan tailored to their requirements, including any additional responsibilities which they may take on (such as membership of Committees). The programme commences at the pre-appointment stage with the provision of targeted, practical information to facilitate due diligence and general familiarisation. It then continues on an incremental basis over the first six months of the appointment, first with introductory meetings with key members of management and then with briefing sessions covering governance, strategy, stakeholder issues, finance and risk management, and human resources strategy (the latter two sessions being targeted specifically at ensuring directors have a clear understanding of the roles of the Audit and Remuneration Committees, even if they do not themselves serve on these Committees). These internal sessions are supplemented by occasional presentations from external advisers on specific topics, such as remuneration issues. Over this period, new directors also undertake site visits to business locations in the UK and US. The cycle of business overview presentations made to the Board serves to deepen each new director s understanding of the company. A record is maintained for each director to track their progress through the induction programme, and a review is conducted at the end of the director s first year in office to assess any further induction requirements.

Two new non-executive directors (Vicky Bailey and Nancy Wilgenbusch) were appointed during the 2004/05 financial year. At the time of appointment of new non-executive directors they are available to meet with shareholders on request.

Continuing professional development is provided through briefing sessions in the course of, or linked to, regular Board meetings, and these cover business-specific and broader

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Corporate Governance

regulatory issues. Topics covered by such briefing sessions during the year have included energy risk management, technology and engineering, company values and the transmission and distribution price reviews. Directors also receive a monthly in-house newsletter highlighting topical developments of relevance to ScottishPower in the fields of corporate governance, company law and related issues. Further, the annual performance evaluation of individual directors (outlined below) provides an opportunity for the training and development needs of Board members to be identified and addressed on a structured basis.

5 Board Performance Evaluation

During the year, the company engaged the Institute of Chartered Secretaries and Administrators (ICSA) to undertake an independent external evaluation of the performance of the Board, its principal Committees (Nomination, Remuneration and Audit) and individual directors. This represented a natural progression from the previous two financial years, during which the evaluation (also conducted externally by the ICSA) had focussed on the performance of the Board as a whole. The evaluation process was led by the Chairman, with the support of the Company Secretary, and progress updates were provided to the Nomination Committee and to the Board. All directors participated in the evaluation, with the exception of Euan Baird who had been absent from the Board for substantially all of the year due to ill health.

The evaluation of the Board and its Committees was conducted on the basis of private interviews held between each individual director and the ICSA facilitator (in the case of the Committees, additional specific questions were asked of Committee members and views were also canvassed from key executives having a close link with the work of the particular Committee as well as, in the case of the Audit Committee, the external auditors). The topics discussed during the course of the interviews included the responsibilities and oversight of the Board, meeting arrangements, information and support, Board composition, and decision-making and output. Similar topics were covered in respect of each of the Committees. The results of these interviews were documented, agreed with the individual director and then collectively formed the basis of a report (including specific recommendations) from the ICSA which was presented to the Board at its meeting in early April 2005.

As regards the evaluation of individual performance, each director completed a questionnaire rating, and provided comments on, their own performance and that of each of their fellow directors against a range of key competencies. These competencies included strategic thinking, commitment and preparedness, listening and communication skills, contribution to decision-making, and constructive challenging of information. In addition to a number of generic statements, additional competencies were included for the roles of Chairman, Chief Executive, executive and non-executive director. Again, the ratings and comments provided were synthesised by the ICSA into a consolidated report for each director. These reports were provided to each director individually and formed the basis of a feedback session between the Chairman and the director. The evaluation of the Chairman followed the same process, with input from the non-executive and executive directors; feedback to the Chairman was provided by the senior independent director. A summary of the results for all directors was provided to the Nomination Committee at its meeting in early April 2005, and informed the Committee in its consideration of those directors to be recommended to the Board for re-election at the forthcoming AGM as well as the broader training and development needs of directors.

The Board was satisfied that the evaluation process was rigorous and effective. The evaluation of the Board as a whole produced another very favourable result, building on the last two evaluations. Good progress was noted in the areas of Board responsibilities, monitoring of management, strategy development, risk assessment, and information provision. Recognising that there is always scope for improvement, the report recommended consideration of a number of issues where further progress could be made. The Board reviewed these points at its meeting in early April 2005 and was supportive of effecting change to address the recommendations. The evaluation of the Committees found them to be generally effective in supporting the Board and a number of the recommendations made echoed the results of the Board evaluation.

6 Relations with Shareholders

The company has a well-established investor relations programme for major shareholders, promoting dialogue through analysts briefings involving the Chief Executive, Finance Director and other members of management, as well as extensive investor roadshows in the UK, US and Europe. As well as reviewing the company s financial and operational performance, these presentations provide shareholders with information on the company s strategy and its delivery. Further communication takes place through site visits, roundtable presentations and timely stock exchange announcements. The Board, and in particular non-executive directors, is kept informed of investors views principally through the distribution of analysts and brokers briefings. In addition, the company undertakes periodic research using Makinson Cowell, an independent adviser, to ascertain the views of shareholders,

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and the conclusions of this research are reported to the Board. These channels are considered to offer the most practical and effective method of communicating shareholder opinion to the Board on a regular basis.

The Chairman and the senior independent director (and indeed other non-executive directors) are available to shareholders in the event of any concerns arising which cannot be addressed through management, or in connection with any significant change to the company s strategy, remuneration policy or governance arrangements. However, it is not the company s practice for the Chairman or senior independent director to meet routinely with major shareholders; it is believed that the approach described in this section offers a more efficient method of maintaining contact with shareholders, and to date there has been little evidence of demand from shareholders for such meetings. As a result, the company has not strictly complied with provision D.1.1 of the Combined Code. The company is committed to keeping this situation under review in the year ahead.

Broader shareholder communication takes place through the company s website, which contains recent company announcements and other useful information, including profiles of Board members and terms of reference of the Nomination, Remuneration and Audit Committees. This Annual Report & Accounts includes a wealth of information for those shareholders who choose to receive it; the Annual Review provides a more concise version which summarises key issues and developments during the year. The Annual General Meeting gives shareholders the opportunity to hear presentations on the company s financial and business performance as well as to question the Board on its stewardship of the company. It is expected that all directors will attend the AGM and that the chairmen of the Nomination, Remuneration and Audit Committees, along with other directors, will be available to answer questions. All resolutions at the AGM are voted by poll, with full results (including the number of votes withheld) published following the close of the meeting.

The company declares and pays dividends on a quarterly basis. This practice has been followed since the time of the merger with PacifiCorp in 1999, at which time the Articles of Association adopted by the company empowered the directors to declare both interim and final dividends. Accordingly, it has not been the company s practice to propose a resolution on the final dividend or on the dividend policy for the approval of shareholders at the AGM. The payment of dividends by the company follows a regular pattern, with the fourth quarter dividend becoming payable during the month of June. If this dividend were to be made contingent on the approval of shareholders at the AGM at the end of July (as has been suggested by certain shareholder representative groups), this payment timetable would be delayed significantly. It is not considered to be in the best interests of shareholders to delay the payment of dividends when any shareholder vote could result only in the level of the proposed dividend being approved or reduced.

7 Report from Nomination Committee

Charles Miller Smith, the Chairman of the company, is the Chairman of the Committee. Mair Barnes and Sir Peter Gregson served on the Committee until their retirement at the AGM on 23 July 2004; Donald Brydon and Nancy Wilgenbusch, both independent directors, were appointed to the Committee with effect from 1 June 2004. The other members of the Committee throughout the year were Nolan Karras, an independent director, and Ian Russell, the Chief Executive. Accordingly, throughout the year, the majority of the members of the Committee have been independent non-executive directors. Details of their qualifications and experience are set out on pages 81 and 82. Andrew Mitchell, Company Secretary, or his deputy, acts as secretary to the Committee.

The Committee has written terms of reference and these are available on the company s website. The terms of reference (which were reviewed by the Committee during the year) provide that the principal role of the Committee is to:

Ø review the structure, size and composition (including the skills, knowledge and experience) required by the Board;

Ø give full consideration to succession planning for directors (in particular, for the key roles of Chairman and Chief Executive), taking into account the challenges and opportunities facing the company and what skills and expertise are needed on the Board in the future;

Ø identify and nominate, for the approval of the Board, candidates to fill Board vacancies as and when they arise;

Ø evaluate the balance of skills, knowledge and experience on the Board and keep under review the leadership needs of the organisation;

Ø keep under review legal and regulatory developments in relation to corporate governance and consider changes to the company s policy and practices to address such developments.

The Committee has developed a robust process for the selection and recruitment of directors. Following a review of the Board s size, composition and diversity, the Committee determines the selection criteria and the role specification. External selection consultants are retained to conduct searches. The Committee reviews the profiles of the candidates and interviews are carried out. The Committee then makes its recommendations to the Board for approval.

Two non-executive directors (Vicky Bailey and Nancy Wilgenbusch) were selected by the Committee during the year. The Committee agreed search criteria, detailing the required experience and diversity profile, which were given to selection consultants in the UK and US. The Committee then considered the profiles of a number of candidates (identified both as a result of the external search and through internal contacts) and meetings were held between members of the Committee (along with other directors) and the favoured candidates. Vicky Bailey was identified by the external consultants while Nancy Wilgenbusch was identified through her membership of the PacifiCorp Pacific regional advisory board and as a result of her profile as a distinguished community administrator. The Committee considered that both candidates fulfilled the search criteria and would make a strong contribution to the Board, bringing differing but equally valuable perspectives to its deliberations.

During the year ended 31 March 2005, the Committee met on four occasions. In addition to identifying and nominating candidates as directors for approval by the Board, the Committee reviewed the composition of the Board and its Committees and considered issues of management succession, in particular in relation to the role of Finance Director. In performance of its corporate governance role, the Committee examined the company s approach to dialogue with major shareholders, considered the directors induction and professional development programme (including monitoring the progress of directors through the programme), oversaw the Board evaluation exercise and approved, for submission to the Board, a statement of the respective responsibilities of the Chairman and Chief Executive.

8 Report from Audit Committee

Nick Rose is the Chairman of the Committee and has also been identified as the audit committee financial expert for Scottish Power plc. Sir Peter Gregson served on the Committee until his retirement at the AGM on 23 July 2004; Vicky Bailey was appointed to the Committee with effect from 1 June 2004. The other members of the Committee throughout the year were Donald Brydon, Philip Carroll and Nolan Karras. All of the members of the Committee are independent non-executive directors. Details of their qualifications and experience are set out on pages 81 and 82. Andrew Mitchell, Company Secretary, or his deputy, acts as secretary to the Committee.

The Committee has written terms of reference and these are available on the company s website. The terms of reference (which were reviewed by the Committee during the year) provide that the principal role of the Committee is to review:

Ø the effectiveness of the system of internal control and consider reports from both internal and external auditors on key risks facing the group and controls over these risks;

policies, compliance with legal and regulatory requirements, judgmental issues and the findings of the external auditors;

Ø the activities and effectiveness of the internal audit function;

Ø the relationship with the external auditors, including the engagement of auditors, the audit scope and approach, fees and performance, and policy on provision of non-audit services by the external auditors and recruitment of former external auditors by the company;

Ø compliance with legal and regulatory requirements;

Ø litigation and claims affecting the group.

In addition, the terms of reference of the Committee encompass the receipt and review by the Committee of any complaints regarding accounting, internal accounting controls or auditing matters and of any confidential, anonymous submissions by employees regarding questionable accounting or auditing matters. They also empower the Committee to engage external counsel or other advisers at the expense of the company.

Meetings of the Committee are normally attended by the Chief Executive, the Finance Director, the Director Group Internal Audit and representatives of the external auditors. However, the Committee holds regular private sessions to meet separately with senior management, representatives of Internal Audit and the external auditors, and, where appropriate, external counsel.

During the year ended 31 March 2005 the Committee met on six occasions. The Committee reviewed the quarterly and annual results announcements of both Scottish Power plc and PacifiCorp and received quarterly reports on the work of the Internal Audit function, including the results of audits undertaken during the period and delivery of the audit plan. It also received more detailed presentations on risk and control issues from the management of each of the four businesses, allowing the Committee to question and challenge management directly on these issues. The Committee also received reports on actions being taken to enhance the control environment relating to legal compliance, including introduction of whistleblowing arrangements across the group to allow employees to raise concerns confidentially through an external agency.

Ø the company s financial statements, including accounting

In addition, the Committee monitored progress on two significant projects affecting the group, namely implementation of International Financial Reporting Standards (IFRS) and Section 404 of the Sarbanes-Oxley Act of 2002. Key issues considered by the Committee in relation to IFRS included the treatment of the group s energy management and treasury activities under International Accounting Standard 39 Financial Instruments: Recognition and Measurement . In relation to Section 404, regular reports from each of the four businesses ensured that the Committee remained aware of progress and issues as they arose during the year.

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9 Internal Control

The directors of ScottishPower have overall responsibility for establishing and maintaining an adequate system of internal controls and for reviewing the effectiveness of the system. The effectiveness of the system is kept under review on a continual basis throughout the year through the work of the Audit Committee on the Board s behalf. The system of internal control is designed to manage rather than eliminate risk. In pursuing these objectives, internal control can only provide reasonable and not absolute assurance against material misstatement or loss.

The Executive Team is responsible for implementing the risk management strategy; ensuring that an appropriate risk management framework is operating effectively across the group; embedding a risk culture throughout the group; and providing the Board and the Audit Committee with a consolidated view of the risk profile of the company, identifying any major exposures and mitigating actions.

The risk management framework and internal control system across the group, which is subject to continuous development, provides the basis on which the company has complied with the Combined Code provisions on internal control.

10 Control Environment

The company is committed to ensuring that a proper control environment is maintained. There is a commitment to competence and integrity and to the communication of ethical values and control consciousness to managers and employees. During the year, the company produced a new document, Compliance Behaviour and the Law, which aims to summarise some of the main legal, regulatory, cultural and business standards applicable to all employees. This document has been distributed to all employees in the UK and to employees of PPM Energy in the US; employees of PacifiCorp are required to adhere to its Guide to Business Conduct, which contains similar content. Furthermore, in compliance with the Sarbanes-Oxley Act of 2002, the company has adopted a Code of Ethics for the Chief Executive, Finance Director and principal accounting officers (a copy of this document will be filed with the company s report to the US Securities and Exchange Commission (SEC) on Form 20-F). Human resources policies underpin that commitment by a focus on enhancing job skills and promoting high standards of probity among staff. In addition, the appropriate organisational structure has been developed within which to control the businesses and to delegate authority and accountability, having regard to acceptable levels of risk.

The company has in place a fraud policy and procedures to ensure that all incidences of fraud are appropriately investigated and reported. The company has also adopted a revised Speaking Out and Whistleblower Protection Policy, incorporating a confidential, external reporting service operated by an independent provider. This Policy covers the reporting and investigation of suspected fraud and misappropriation, questionable accounting, financial reporting or auditing matters, breaches of internal financial control procedures, and serious breaches of behaviour and ethical principles. It provides for all such reports made through the external service, and all other internal reports judged material, to be communicated to the Audit Committee. Again, PacifiCorp currently adheres to its own procedure in this regard, offering employees the alternative of contacting an internal fraud hotline or reporting breaches of the Guide to Business Conduct to designated internal company officers or the PacifiCorp ombudsman. These reports are communicated to the Audit Committee on the same basis as under the Speaking Out and Whistleblower Protection Policy.

A Disclosure Committee, constituted at management level, is in place to ensure effective disclosure controls are operating around the production of key published financial statements and to provide assurance to the Chief Executive and Finance Director that they may sign their formal certification to the SEC in accordance with Section 302 of the Sarbanes-Oxley Act of 2002.

11 Identification and Evaluation of Risks and Control Objectives

The company s strategy is to follow an appropriate risk policy, which effectively manages exposures related to the achievement of business objectives.

Each business identifies and assesses the key business risks associated with the achievement of its strategic objectives. Any key actions needed to enhance the control environment are identified, along with the person responsible for the management of the specific risk. Each month, a detailed review of the key risks, controls and action plans within each of the businesses takes place and a Risk Report is produced for review and challenge by the business boards at their monthly meetings. This is a key tool in ensuring the active management of risk across the organisation.

Business controls managers have been appointed within each of the businesses to help ensure that the risk management and internal controls system is consistently adopted, updated and embedded into the business processes.

The corporate centre also considers those risks to the group s strategic objectives that may not be identified and managed at a business level.

The Board and Executive Team receive on a monthly basis the groupwide Risk Report, together with supporting documentation, for review. This report highlights the most

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significant risks across the group and the actions being taken to mitigate them, and also identifies the individuals responsible for the management of these risks. The information being supplied to the Board and Executive Team is continually being developed to include quantitative measures such as sensitivity analyses and Value-at-Risk calculations for issues reported in the Group Energy Risk Report.

The use of a well-defined risk management methodology across all businesses allows a consistent and coordinated approach to risk reporting for review by the Board, which also receives regular reports on these matters from the Audit Committee, to enable the directors to review the effectiveness of the system of internal control on a regular basis.

A key element and requirement of the risk evaluation process is that a written certificate is provided quarterly by all members of the Executive Team, confirming that they have reviewed the effectiveness during the period of the system of internal control under their responsibility.

A further measure in managing exposure to risk is the ongoing development of a formalised and coherent approach to business continuity management, which is underpinned and validated by testing and continuous development.

12 Energy Management

A Group Energy Risk Committee (GERC) has been established to assist the Executive Team in ensuring that there is an appropriate risk and control governance framework in place over energy activities. The GERC meets monthly and the key responsibility of this group is to make suitable recommendations to the Executive Team on energy-related risk policy issues. In addition, the Group Energy Risk Director, with other members of the GERC, continues to enhance business processes and systems to ensure that all risks pertaining to the energy management businesses are understood, quantified, managed and reported on a consistent basis across the group.

The GERC also provides advice and guidance to the businesses on interpretation and execution of the Group Energy Management and Risk Management Policy.

13 Capital Investment

capital budgeting process, and to monitor the post-investment appraisal process. In particular, the GIC reviews all business acquisitions and disposals and new business ventures.

14 Monitoring and Corrective Action

The Executive Team reviews monthly the key risks facing the group and the controls and monitoring procedures for these. Operation of the group s control and monitoring procedures is reviewed and tested by the group s Internal Audit function under the supervision of the Director Group Internal Audit, with a direct reporting line to the Audit Committee and to the Finance Director. Internal Audit reports and recommendations on the group s procedures are reviewed regularly by the Audit Committee. The external auditors also provide reports to the Audit Committee on matters in relation to the group s internal financial control procedures identified during the course of their audit. The Audit Committee also receives regular reports on the continued development, implementation and evaluation of the risk management and internal control system.

15 Auditor Independence

The Audit Committee and the firm of external auditors have safeguards to avoid the possibility that the auditors objectivity and independence could be compromised. These safeguards include adoption by the Audit Committee of a policy regarding pre-approval of audit and permitted non-statutory audit services provided by the external auditors and a policy on the hiring of former external audit staff by the group.

Where the work to be undertaken is of a nature that is generally considered reasonable to be completed by the external auditors for sound commercial and practical reasons, including confidentiality, the conduct of such work will be permissible provided that it has been pre-approved by the Audit Committee. Examples of pre-approved services include the completion of regulatory audits, provision of taxation and regulatory advice, reporting in relation to SEC and UK Listing Authority requirements and the completion of certain financial due diligence work. Under the policy, any work performed in excess of a pre-defined limit (being an initial fee value in excess of £100,000) must also be approved by the Finance Director and the Chairman of the Audit Committee.

Substantial capital investment proposals are reviewed by the Group Investment Committee (GIC), chaired by the Finance Director, to ensure that they are in line with the group s strategy, achieve the required rate of return, comply with legal requirements and commercial practice, and are supported by robust financial analysis. The role of the GIC, acting on behalf of the Executive Team, is to review the group s capital programme, monthly and quarterly capital expenditure and

Fees paid to the external auditors during the year ended 31 March 2005 (with equivalent information for the year ended 31 March 2004) are shown in Table 47 below:

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Ø **Table 47**

Auditors remuneration

	2004/05	2003/04
	£m	£m
Audit services		
statutory audit	**1.7**	1.5
audit-related regulatory reporting	**0.7**	0.4
Further assurance services	**2.5**	0.7
Tax services		
compliance services	**1.0**	1.6
advisory services	**0.4**	0.8
Total UK and US audit and non-audit fees paid to auditors	**6.3**	5.0

Further assurance services principally represents fees associated with due diligence work and advice regarding the implementation of s404 of the Sarbanes-Oxley Act of 2002 and the implementation of International Financial Reporting Standards (IFRS).

All of these fees were either specifically approved by the Audit Committee or were subject to the pre-approval procedure described above.

Safeguards are also in place to protect the independence of the Internal Audit department. The department reports directly to the Audit Committee; the Committee reviews the Internal Audit work plan and sets the department s budget. In addition, the Committee is required to approve the appointment, replacement, reassignment or dismissal of the Director Group Internal Audit.

16 Evaluation of Disclosure Controls and Procedures (Sarbanes-Oxley Act of 2002)

The Chief Executive and the Finance Director have evaluated the effectiveness of the group s disclosure controls and procedures as at the end of the period covered by this report. Based on this evaluation, the Chief Executive and Finance Director concluded that the disclosure controls and procedures (as they are defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended) are effective.

on the group s short- and long-term value. SEE matters are also included in the induction and development programme for directors.

In terms of risk identification and management, SEE matters are included in the overall risk and control framework and in the Risk Report which is reviewed on a monthly basis by the Board and Executive Team. The company also employs management tools such as balanced scorecards to measure progress against key strategic priorities and has developed an International Leadership Model which integrates values with performance throughout the business.

Further information regarding SEE matters can be found in the Business Review section of this Report. In addition, the company publishes separately an Environmental and Social Impact Report, which includes information on the company s SEE policies and practices and internal governance structures, and individual performance reports which will appear on the company s website. The Environmental and Social Impact Report and the performance reports are verified and independently assured by csr network, a corporate social responsibility consultancy firm.

18 Political Donations and Expenditure

ScottishPower is a politically neutral organisation but is required to comply with the Political Parties, Elections and Referendums Act 2000. This legislation defines political donations and expenditure in wider terms than would be commonly understood by these phrases. The definitions include expenditure which the Board believes it is in the interests of the company to incur. The Act also requires companies to obtain prior shareholder approval of this expenditure; at the Annual General Meeting in 2004 the company obtained authorisation up to a maximum amount of £100,000.
During the financial year ended 31 March 2005, the company paid a total of £26,645 for activities which may be regarded as falling within the terms of the Act. The recipients of these payments were:

Ø The Labour Party £18,095

Ø The Conservative and Unionist Party £3,500

There has been no change to the group s internal controls that has materially affected, or is reasonably likely to materially affect, these controls over financial reporting during the period covered by this report.

17 Social, Environmental and Ethical Matters

The Board receives monthly operational reports which include consideration of relevant developments across the group in social, environmental and ethical (SEE) matters. This enables the Board to take regular account of the strategic significance of SEE matters to the group, and to consider the risks and opportunities arising from these issues that may have an impact

- Liberal Democrats £1,300
- Scottish National Party £2,750
- Plaid Cymru £1,000.

These activities comprised the sponsorship of briefings and receptions at party conferences and attendance at party events. These occasions present an important opportunity for the company to represent its views on a non-partisan basis to politicians from across the political spectrum. The payments do

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not indicate support, and are not intended to influence support, for any particular political party.

It should be noted that these activities do not contravene the restrictions on political contributions under the US Public Utility Holding Company Act of 1935, to which the company is subject.

19 NYSE Corporate Governance Rules

The New York Stock Exchange (NYSE) issued extensively revised corporate governance rules for its listed companies in 2003 and these were updated in November 2004. While these rules are mandatory for US incorporated companies whose shares are listed on NYSE, foreign issuers such as Scottish Power plc are exempt from a number of the requirements and may adopt different practices that reflect home country practice. With the exception of two specific areas, the company complies fully with these rules, which are broadly comparable to the requirements of the Combined Code. The two areas where the company does not comply with the NYSE rules are:

Ø **Composition of the Nomination Committee** in line with UK corporate governance practice, the Nomination Committee comprises a majority of independent non-executive directors, but does also include both the Chairman and Chief Executive. The NYSE rules would require all members of the Committee to be independent.

Ø **Adoption of Corporate Governance principles** UK listed companies are required either to comply with the Combined Code or explain why they have not done so. As a result, the Combined Code in effect provides a set of corporate governance principles for the company addressing all of the corporate governance guidelines described in the NYSE rules, and accordingly the company does not believe that additional company-specific principles are necessary.

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Remuneration Report of the Directors

1 Consideration of Remuneration Matters by the Directors

The ScottishPower Board is responsible for determining the remuneration policy for the ScottishPower group. The Remuneration Committee, with delegated authority from the Board, determines the detail of remuneration arrangements for the Executive Team, including the executive directors, and reviews proposals in respect of other senior executives. The relationship between the Board and the Committee is based on formal Terms of Reference, which are available on the company s website, and are regularly reviewed to ensure that they reflect best practice.

The Remuneration Committee consists solely of independent non-executive directors. Its members are Nolan Karras (Chairman), Euan Baird, Donald Brydon, Philip Carroll, Nick Rose and Nancy Wilgenbusch (the latter two directors were both appointed to the Committee on 1 June 2004). Sir Peter Gregson was Chairman of the Committee, and Mair Barnes was a member, until their retirement from the Board at the AGM on 23 July 2004. These members have no personal financial interest, other than as shareholders, in the matters considered by the Committee. Details of the payments made to all non-executive directors are set out in Table 48 (page 101).

The Chairman of the company, Charles Miller Smith, and the Chief Executive, Ian Russell, are invited to attend meetings and may provide guidance on the impact of remuneration policy and advise, as appropriate, on the performance of senior executives. They are not present during any discussion of their own remuneration. The Terms of Reference contain conflict of interest provisions to ensure that no directors are involved in any decision relating to their own remuneration.

The Committee is able to draw on advice from independent remuneration consultants and internal expertise. Towers, Perrin, Forster & Crosby, Inc., (Towers Perrin) act as remuneration consultant and independent advisor to the Committee. Towers Perrin s appointment by the Committee followed a competitive tendering exercise. Towers Perrin also provides remuneration and other human resources consultancy services directly to some ScottishPower companies within parameters established by the Committee. The Terms of Reference of the independent remuneration advisors are available on the company s website. Company executives whom the Committee may consult include the Group Company Secretary, (who acts as Secretary to the Committee), the Group Director, Human Resources, the Director Group Talent Management and Reward, and the Head of Group Reward. The Terms of Reference of the Remuneration Committee empower it to avail itself of external legal and professional advice at the expense of the company.

The Committee met on two occasions during the year ended 31 March 2005.

During the year, the Board accepted all of the recommendations from the Committee without significant amendment.

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Remuneration Report of the Directors

2 Statement of Remuneration Policy

Philosophy and Policy

ScottishPower seeks to ensure that remuneration and incentive schemes are in line with best practice, provide a strong link to individual and company performance and promote a community of interest between employees and shareholders.
Rewards for executives and directors are designed to attract and retain individuals of high quality, who have the requisite skills and are incentivised to achieve levels of performance which exceed that of competitor companies. As such, remuneration packages must be market-competitive and capable of rewarding exceptional performance. All senior management remuneration packages are set according to a mid-market position, with packages above the mid-market level provided only where supported by demonstrably superior personal performance. Remuneration packages are developed to reflect the prevailing market practice in each business environment.

Annual bonus arrangements have been structured so that stretching targets are based on corporate, business unit and individual performance.

The company operates a Personal Shareholding Policy (PSP), requiring executives and key senior managers to build-up and retain a shareholding in the company in proportion to their annual salaries. These proportions are three times base salary for the Chief Executive and two times base salary for other executive directors. The Committee expects PSP participants to have accumulated their respective shareholding targets within eight years of the introduction of the Policy, that is by the end of May 2008, or eight years after the first award under any discretionary share plan for external appointees to the Board. The Committee reviews this policy regularly to ensure that it is in line with evolving best practice and in the interests of shareholders.

In setting remuneration levels, the Committee commissions an independent evaluation of the roles of the Executive Team. The Committee takes independent advice from Towers Perrin on market-level remuneration, based on comparisons with other companies of similar size and complexity, including the major utility companies, with which the company competes for executive talent.

The Committee recognises the importance of linking rewards to business and personal performance and believes that the arrangements detailed below provide an appropriate focus on performance and balance between short- and long-term incentives. The annual bonus plan and long-term incentive arrangements are expected to provide 51% of total reward for the achievement of stretching target objectives. Higher proportions of performance-based reward are available for the delivery of exceptional personal and business performance resulting in enhanced shareholder governance practice. The Long Term Incentive Plan will expire at the 2006 AGM having reached the end of its ten-year lifespan. The Committee will, therefore, design an appropriate new long-term incentive plan for shareholder approval at the 2006 AGM. Prior to this the Committee will consult with major shareholders. At this time, no other substantial changes to the company s policies with regard to directors remuneration are envisaged over the next year and in subsequent years. However, the Committee may develop policy and, should it determine any changes to be appropriate, will report such changes to shareholders through established channels of consultation and reporting.

3 Elements of the Remuneration Package 2004/05

Base Salaries

The Committee sets base salaries for the Executive Team by reference to individual performance through a formal appraisal system applied to all management employees, and to external market data, reflecting similar roles in comparable companies. Account is also taken of salary increases and employment conditions across the company.

Annual Performance-Related Bonus

Executive directors and senior management participate in the company s performance-related annual incentive plans. Any payments to UK executives under the plans are non-pensionable and are determined by the Committee following assessment against stretching pre-determined targets. In line with US market practice, a proportion of bonus paid to US senior executives, including Judi Johansen the CEO of PacifiCorp, is pensionable.

The maximum annual incentive payment available to executive directors is 100% of base salary. 75% of any award is paid immediately in cash and 25% is deferred into company shares that are released to the individual after 3 years.

The 2004/05 annual incentive plan for the Chief Executive was based 45% on the achievement of key company financial targets, including Earnings per Share (EPS), interest cover, cash flow and return on value.

The Committee constantly monitors market practice in order to remain competitive, to ensure that reward policy supports company strategy and to reflect good corporate

capital. A further 45% was based on the achievement of key strategic objectives (including appropriate pre-determined targets in relation to customer service and health and safety, amongst others) and 10% was based on cultural and leadership behaviours.

For the other four executive directors, 25% of bonus was based on the achievement of key company financial targets, 25% was based on the achievement of key strategic objectives, 40% on the achievement of the appropriate function/division balanced scorecard targets (with financial metrics and performance targets relating to the function/division, including, where appropriate, customer service and health and safety metrics) and 10% was based on cultural and leadership behaviours.

Objectives are set annually by the Committee and performance against these is reviewed by the Committee at the

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half year and year end. In determining annual incentive payments for 2004/05, the Remuneration Committee gave detailed consideration to outturn against target in relation to company, divisional/functional and personal performance.

Payments made to executive directors were within the range of 53% to 96% of the maximum available opportunity.

Executive Share Plans

The company currently operates a performance share plan, known as the Long Term Incentive Plan (LTIP) for executive directors and other senior managers. In May 2004, the company made the final award under the Executive Share Option Plan 2001 (ExSOP).

Under the LTIP, awards to acquire shares in ScottishPower at nil or nominal cost are made to the participants up to a maximum value, at the time of grant, equal to 75% of base salary. The award will vest only if the Committee is satisfied that there has been sustained underlying performance of the company and, to this end, certain gateway performance targets are measured and the Committee reviews performance against these measures when determining if awards vest. The measures relate to the key financial performance indicators of the company and customer service standards. These measures provide a mechanism to safeguard stakeholder interests and provide an overview of the financial and operational success of the business.

The number of shares which actually vest is dependent upon the company s comparative Total Shareholder Return (TSR) performance, over a three-year performance period. TSR measures ScottishPower s comparative performance against key competitors and only provides rewards if ScottishPower is at least equal to the median performance of appropriate comparators. The Committee chose TSR as the performance measure for the LTIP as it believes that it provides a clear link to the creation of shareholder value.

LTIP awards were granted to 54 directors and senior executives during the year (Award 9). TSR performance is measured against an international comparator group of 37 major energy companies, as identified below.

AES Corp; American Electric Power Inc; Calpine Corp; Centrepoint Energy Inc; Centrica; Chubu Electric Power Co Inc; CLP Holdings Limited; Constellation Energy Group Inc; Dominion Resources Inc; Duke Energy Corp; Dynegy Inc; Edison International; El Paso Corp; Electrabel SA; Electricidade de Portugal SA; Endesa SA; Ente Nazionale per l Energia Elettrica SpA (Enel); Entergy Corp; Exelon; FirstEnergy Corp; FPL Group Inc; Gas Natural SDG SA; Iberdrola SA; Kansai Electric Power Co Inc; National Grid Transco plc; PPL Corp; Progress Energy Inc; Public Service Enterprise Group Inc; RWE AG; Scottish and Southern Energy plc; Southern Company Inc; Tenaga Nasional Bhd; Tokyo Electric Power Co Inc; TXU Corp; Union Fenosa; Williams Companies Inc; and Xcel Energy Inc.

No shares vest unless the company s TSR performance is at least equal to the median performance of the comparator group, at which point 40% of the initial award vests. 100% of the shares vest if the company s performance is equal to or exceeds the top quartile. The number of shares that vest for performance between these two points is determined on a straight-line basis.

For LTIP Award 6, which had the potential to vest during the year, TSR performance was measured against a similar composition of international energy companies over the three-year period to 31 March 2004. After careful consideration, the Committee determined that the gateway measures relating to the financial and customer service performance of the company had been achieved. As the company was ranked at the median TSR performance level against the comparator group, 40% of the initial award vested. This meant that at the maximum level of participation whereby awards were made over shares with an initial value of 75% of base salary at May 2001, an award equal to 30% of base salary at May 2001, became available for exercise by participants in May 2004.

The Committee has approved the operation of the LTIP for 2005/06 and will continue to focus on performance and potential in determining LTIP participation. As an additional incentive and retention tool, the Committee will include selected key high potential/high performance individuals in the LTIP as identified by the talent management process (if not already at a level that qualifies for participation). The Committee has also agreed that participants who would normally receive an LTIP award as a result of their level in the company will only do so if they achieve a certain pre-determined level of performance as determined by the company s performance management system. No significant changes to the operation of the LTIP have been implemented for 2005/06 and this will be the final grant under this plan as it will reach the end of its 10-year lifespan.

ExSOP awards were granted at market value to 300 senior executives including the Executive Directors in May 2004. Executive directors in post at May 2004 received an award of options with a value equivalent to 200% of base salary. Options granted to UK executives under the ExSOP are subject to the performance criterion that the average annual percentage increase in the company s EPS be at least 3% (adjusted for any increase in the Retail Price Index). The Committee believes that EPS is an appropriate measure for the purposes of testing the ExSOP because it is based on the underlying financial performance of the company. This criterion is assessed at the end of the third financial year, the first year being the financial year starting immediately before the date of grant. If not satisfied on the third anniversary, the criterion may be retested, from the same base, on the fourth and fifth anniversaries of grant. Unvested options lapse at the fifth anniversary. The Company will make no further awards under the ExSOP.

Performance Graph

The Directors Remuneration Report Regulations require that a graph be presented showing the company s TSR performance against the TSR performance of a broad equity market index over a five-year period. The FTSE 100 has been chosen because

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Remuneration Report of the Directors

it is the principal index in which the company s shares are quoted. The graph below presents the comparative TSR performance of the company during the period 1 April 2000 31 March 2005. The graph shows that ScottishPower has outperformed the index over this period.

This graph looks at the value (net of withholding tax), at 31 March 2005, of £100 invested in ScottishPower on 31 March 2000 compared with that of £100 invested in the FTSE 100 Index. The other points plotted are the values at intervening financial year ends.

All-Employee Share Plans

To facilitate high levels of share ownership by employees, the company operates three savings-related share ownership plans. These are all-employee Inland Revenue or Internal Revenue Service approved plans and are not subject to performance conditions. Participation is available to executive directors on the same basis as to all other eligible employees.

Sharesave

Employees domiciled in the UK are eligible to participate in the ScottishPower all-employee Sharesave plan. Under this plan, options are granted over ScottishPower shares at a discount of 20% from the prevailing market price at the time of grant to eligible employees who commit to save up to £250 per month over a period of three or five years.

Employee Share Ownership Plan (ESOP)

The company operates an ESOP (also known as a Share Incentive Plan) for all UK domiciled employees. The ESOP enables employees to purchase shares in the company from pre-tax income up to the limits specified in the legislation. The value of these shares is at risk as they are not normally released until the legislation allows. The company matches these shares at no cost to the employee on a one-for-one ratio.

Defined Contribution Savings Plan (401(k))

Employees domiciled in the US are eligible to participate in a tax-beneficial savings plan (known as a 401(k) plan) provided for all US employees. The Plan provides for employee contributions up to statutory limits, which are matched by the company at 50% of the employee contribution up to the first 6% of pay (i.e. a 3% match). The company also makes an additional contribution of 2% of eligible pay for all participants. All contributions to the Plan are invested in a range of investment funds, including ScottishPower American Depositary Shares (ADS), at the discretion of the participant.

Pension

The UK domiciled executive directors, and other UK senior managers of the company, are provided with pension benefits through the company s main pension scheme, and through an executive top-up pension plan which provides a maximum pension of two-thirds of final salary on retirement at age 63, reduced where service to age 63 is less than 20 years. Pensionable salary is normally base salary in the 12 months prior to leaving the company although there are prescribed mechanisms for calculating pensionable salary by averaging base salary over a period of up to three out of the last 10 years service. The employee contributes 5% of salary to the scheme. Life assurance provision of four times pensionable salary and a widow s pension of half the executive s pension on death are provided.

UK domiciled individuals who joined the company on or after 1 June 1989 are subject to the Inland Revenue earnings cap , introduced by the Finance Act 1989. Entitlement to pension benefits above the cap cannot be provided through the company s approved pension scheme, and therefore arrangements on an unapproved basis have been made to provide total benefits for executives affected by the legislation as though there was no cap. The total liability calculated on an FRS 17 basis in respect of executives and senior employees arising in relation to unapproved benefits accrued for service for the year to 31 March 2005 was £1,520,900. The Trustee body of the Executive Top Up Plan is chaired by the Company Secretary.

The Committee has considered, at length, the company s response to the government s simplification of the pensions taxation regime to take effect on 6 April 2006 (A-day). In determining future executive pensions policy, the Committee ensured that no additional benefit would accrue to executive directors as a result of the taxation reform. The Committee has decided that the unapproved promise will remain the sole vehicle for providing executive pensions above the new Life Time Allowance.

The US domiciled executive director and other US senior managers of the company participate in a qualified defined benefit pension plan and a Supplemental Executive Retirement Plan. The defined benefit plan is a non-contributory retirement plan. Benefits vest after five years of service and are determined by each employee s years of service with the company, final average pay (the highest 60 consecutive months of eligible pay over the last 120 months of employment) and age at retirement. Pay includes base pay plus annual incentive plan payments up to 10% of annual base pay. The amount of pay considered under the plan is further limited by statute. Benefits under the plan, plus benefits payable from the US Social Security system, at age 65 (normal retirement) are targeted to replace 60%-70% of final average pay after a full career (defined as 30 years) with the company.

As a US domiciled executive director, Judi Johansen participates in the PacifiCorp Supplemental Executive Retirement Plan (SERP) which provides additional retirement benefits to a select group of management or highly compensated employees as a means to attract and retain highly effective individuals. Participants receive benefits at retirement based on length of service with the company and average pay in the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose would include salary and annual incentive plan payments. Benefits are based on 50% of final average pay plus 1% of final average pay for each year that the Company meets certain performance goals set for each fiscal year by the Company. The maximum benefit is 65% of final average pay. Retirement benefits are reduced to reflect Social Security benefits as well as certain prior employer retirement benefits and other retirement benefits from the company s qualified retirement plan. Participants are entitled to receive full benefits upon retirement after age 60 with at least 15 years of service. Participants are also entitled to receive reduced benefits upon early retirement after age 55 or after age 50 with at least 15 years of service and 5 years of participation in the supplemental plan.

The Committee has reported the pension expense in accordance with the requirements of the UK Listing Authority and Directors Remuneration Report Regulations. Pension costs detailed in the Accounts are calculated as the cost of providing benefits accrued in the 2004/05 year, in accordance with appropriate accounting standards.

Benefits

Executive directors are eligible for a range of benefits on which they are assessed for tax. These include the provision of a company car or a cash allowance in lieu of a car, fuel, private medical provision and permanent health insurance. The provision and level of benefits is reviewed regularly to ensure that practice is in line with the market.

The US domiciled executive director participates in post-retirement healthcare plans, subject to the eligibility criteria at termination from the company. Currently, those criteria are termination after age 55 with five or more years of service.

Service Contracts

Ian Russell, Charles Berry and David Nish entered into revised service contracts with the company dated 3 June 2003. On appointment to the Board, Simon Lowth and Judi Johansen entered into new service contracts with the company on 1 September 2003 and 1 October 2003 respectively.

These are rolling contracts terminable by either party on no more than 12 months notice. They contain a payment in lieu of notice provision that allows the company to terminate the contract immediately and a liquidated damages provision which provides for a payment to the director if the company terminates the contract unlawfully. The payment in lieu of notice and liquidated damages provisions are calculated by reference to 12 months basic salary and contractual benefits (except bonus, pension and share-related incentives as set out below). With the exception of the US director, Judi Johansen, the company has the discretion to pay these amounts in full on termination of employment or, in line with emerging best practice, in instalments. If instalments are paid, an initial payment will be made in respect of six months loss only. Further instalments may be paid if the director has not started alternative employment within six months of the termination date. The director will only receive payment in respect of 12 months loss should he or she fail to start alternative employment within nine months of termination. If the director starts alternative employment within nine months of termination, the instalments will be reduced by the basic salary received by the director in his alternative employment. In line with US market practice any payments to be paid to the US director on unlawful termination of the contract shall be paid on regular Company pay dates or as otherwise agreed by both parties. If the director commences other employment within six months following termination of employment, severance pay and benefits will not be offset by any salary received from an alternative employer. If other employment commences after six months following termination of employment, any remaining severance pay due will be reduced by any salary or bonus received from alternative employment for the remainder of the severance pay period.

The director s entitlement under any performance related pay scheme for the period prior to termination will be unaffected as will any entitlement under any executive share scheme. In addition, the company will pay to the director an amount representing a proportion of his or her maximum annual bonus for the notice period based on the company s performance against its pre-determined financial objectives. This will be paid at the same time as annual bonuses are paid to other employees providing the director has complied with confidentiality obligations and any restrictive covenants and may be reduced if the director obtains alternative employment.

The service contract does not provide for any additional benefits where termination of a director is as a result of a change in control of the company.

If not otherwise terminated, the service contracts terminate automatically at Normal Retirement Age.

The company s policy is that all new directors will be offered service contracts on the terms outlined above.

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The Committee s policy on early termination is to emphasise the duty to mitigate to the fullest extent practicable. Senior managers within the company have notice periods ranging from six months to one year.

The Chairman, Charles Miller Smith, does not have a service contract with the company.

The Remuneration Committee, in light of the expected timetable for obtaining regulatory approvals for PacifiCorp s sale to MidAmerican, approved a cash retention award for PacifiCorp s Chief Executive Officer, Judi Johansen, equal to one times base salary, which is contingent on the closing of PacifiCorp s sale to MidAmerican and also on her continued employment and her satisfactory performance of duties in the period through the sale s closing. She will receive 80% of the retention award upon the closing of the sale and the remaining 20% of the award 365 days from the date of the closing, provided there have been no breach of warranty claims against ScottishPower or PacifiCorp Holdings, Inc. under the Stock Purchase Agreement with MidAmerican.

External Non-Executive Appointments

The company encourages its Executive Directors to become non-executive directors of other companies, provided that these appointments are not with competing companies, are not likely to lead to any conflicts of interest, and do not require extensive commitments of time which would prejudice their roles within the company. This serves to add to their personal and professional experience and knowledge, to the benefit of the company. Any fees derived from such appointments may be retained by the executives.

In this respect, during 2004/05 Charles Berry received a fee of £1,135 from the Securities Trust of Scotland in his position as non-executive director. No other Executive Director receives remuneration from their respective external non-executive roles.

Remuneration Policy for Non-Executive Directors

The remuneration of non-executive directors is determined by the Chairman and the executive directors of the Board and consists of a base fee of £31,000 p.a., a committee membership fee of £5,000 p.a. (not paid to a committee chairman), a fee of £15,000 p.a. for chairing the Audit Committee and the Remuneration Committee, and an international travel fee of £1,000 for attending a tranche of meetings that involve a Transatlantic journey.

bonus, share option or other profit or long-term incentive plan. Full details of the remuneration of the non-executive directors are contained in Table 48.

Compensation of Directors and Officers

For US reporting purposes, it is necessary to provide information on compensation and interests for directors and officers. The aggregate amount of compensation paid by the group to all directors and officers of the company, as a group, was £7,488,467.

During 2004/05 the cost to the group to provide pension, retirement or similar benefits for directors and officers of the company pursuant to any existing plan provided or contributed to by the group was £4,720,784 (calculated in accordance with Statement of Standard Accounting Practice 24 Accounting for pension costs).

Interest of Management in Certain Transactions

There have been no material transactions during the group s three most recent financial years, nor are there presently proposed to be any material transactions to which the company or any of its subsidiaries was or is a party and in which any director or officer, or 10% shareholder, or any relative or spouse thereof or any relative of such a spouse, who had the same home as such person or who is a director or officer of any subsidiary of the company has or is to have a direct or indirect material interest.

During the group s three most recent financial years there has been no, and at present there is no, outstanding indebtedness to the company or any of its subsidiaries owed or owing by any director or officer of the group or any associate thereof.

Directors Interests

Other than as disclosed, none of the directors had a material interest in any contract of significance with the company and its subsidiaries during or at the end of the financial year. The directors interests, all beneficial, in the ordinary shares of the company, including interests in options under the company s ExSOP and Sharesave Scheme and awards under the LTIP, are shown on pages 102 to 105.

With effect from 1 April 2004, the Board introduced a fee of £10,000 p.a. for chairing the Group Finance Committee of the Board and £3,000 p.a. to be a member. Such fees are only paid to the independent non-executive directors who serve on the Group Finance Committee.

Effective from 1 August 2004, the Board introduced a fee of £10,000 p.a. for the role of Senior Independent Director.

In line with best practice, the independent non-executive directors do not have service contracts, but are appointed under standard letters of appointment. They are not members of the company s pension schemes and do not participate in any

Directors Emoluments

Table 48 provides a breakdown of the total emoluments of the Chairman and all the directors in office during the year ended 31 March 2005.

Directors Pension Benefits

Details of pension benefits earned by the executive directors during the year are shown in Table 49.

The following tables provide details of the remuneration, pensions and share interests of the directors and the information is audited.

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Table 48

Ø Directors Emoluments 2004/05

	Basic Salary		Bonuses		Benefits in Kind		Total	
	£ 000 s		**£ 000 s**		**£ 000 s**		**£ 000 s**	
Total Emoluments	**2005**	2004	**2005**	2004	**2005**	2004	**2005**	2004
Chairman and executive directors								
Charles Miller Smith (Non-Executive Chairman)	**275.0**	275.0				4.7	**275.0**	279.7
Ian Russell	**705.0**	650.0	**627.5**	414.4	**47.6**	32.7	**1,380.1**	1,097.1
Charles Berry	**400.0**	315.0	**382.0**	212.6	**37.7**	27.4	**819.7**	555.0
Judi Johansen*	**406.3**	206.6	**213.3**	258.3	**11.5**	3.2	**631.1**	468.1
Simon Lowth	**430.0**	242.1	**354.8**	151.3	**16.1**	6.7	**800.9**	400.1
David Nish	**430.0**	415.0	**387.0**	269.8	**41.8**	31.7	**858.8**	716.5
Total	**2,646.3**	2,103.7	**1,964.6**	1,306.4	**154.7**	106.4	**4,765.6**	3,516.5

	Fees		Bonuses		Benefits in Kind		Total	
	£ 000 s		**£ 000 s**		**£ 000 s**		**£ 000 s**	
	2005	2004	**2005**	2004	**2005**	2004	**2005**	2004
Non-executive directors (fees and expenses)								
Euan Baird	**37.0**	32.8				2.9	**37.0**	35.7
Mair Barnes (retired 23 July 2004)	**13.7**	38.0			**0.6**	3.4	**14.3**	41.4
Donald Brydon	**53.8**	29.6			**13.4**	0.1	**67.2**	29.7
Philip J Carroll	**55.0**	23.8			**0.6**	1.5	**55.6**	25.3
Sir Peter Gregson (retired 23 July 2004)	**18.7**	51.0			**0.7**	3.0	**19.4**	54.0
Nolan Karras**	**64.3**	53.9				3.7	**64.3**	57.6
Nick Rose	**55.1**	38.8			**11.8**	1.7	**66.9**	40.5
Vicky Bailey (appointed 1 June 2004)	**34.5**				**2.2**		**36.7**	
Nancy Wilgenbusch** (appointed 1 June 2004)	**39.9**						**39.9**	
Total	**372.0**	267.9			**29.3**	16.3	**401.3**	284.2

Other emoluments

* Conversion rate used for Judi Johansen is £1 = $1.846, being the average exchange rate during the year.

** Nolan Karras and Nancy Wilgenbusch received emoluments in the US of £8,667 (2004 £9,637) and £2,709 respectively. These amounts relate to services to the Utah and Pacific regional advisory boards and are paid in the form of cash and shares. The amounts are included within Fees in the above table.

(i) The emoluments of the highest paid director (Ian Russell) excluding pension contributions were £1,380,079 (2004 £1,097,144). Details of share related incentives are contained in Tables 50 and 51.

(ii) Ian Russell has an entitlement under the unapproved pension benefits described further in Table 49.

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Table 49

Ø Defined Benefits Pension Plans 2004/05

Year	Transferred - in benefits £ p.a.	Additional pension earned in year (net of inflation) £ p.a.	Accrued pension at end of year £ p.a.	(A) Transfer value of increases after inflation (net of director s contribution) £	Value of accrued pension at start of year £	Value of accrued pension at end of year £	(B) Total change in value during the year (net of director s contributions) £
Ian Russell	19,347	31,017	246,803	430,932	2,637,029	3,385,630	743,500
Charles Berry		37,397	152,287	525,393	1,416,165	2,125,091	703,827
Judi Johansen*		20,401	59,547	78,327	146,921	252,611	105,689
Simon Lowth	34,577	12,005	53,529	116,115	347,141	530,246	178,005
David Nish	45,867	9,472	116,958	102,078	1,020,190	1,297,583	272,293

* Part of Judi Johansen s benefits are provided in defined contribution form, through a company 401(k) plan. The figures in the table do not include any 401(k) element. The company contribution payable to the 401(k) plan in respect of Judi Johansen for the period 1 April 2004 to 31 March 2005 was £6,540. See also note (xi) regarding her potential entitlement to post-retirement healthcare benefits. The conversion rate used is £1=$1.846 being the average exchange rate during the year.

(i) The accrued entitlement of the highest paid director (Ian Russell) was £246,803 (2004 £208,489). During the year, retirement benefits were accrued under the defined benefits pension scheme in respect of five directors (2004 five directors).

(ii) The transfer value of the increases after inflation (A) represents the current capital sum which would be required, using demographic and financial assumptions, to produce an equivalent increase in accrued pension and ancillary benefits, excluding the statutory inflationary increase, and after deduction of members contributions. Although the transfer value represents a liability to the Pension Scheme in respect of approved benefits and to the company in respect of any unapproved benefits, it is not a single sum paid or due to be paid to the individual director and cannot therefore meaningfully be added to the annual remuneration. Instead, this value would not be payable until the director s retirement date, and thereafter would be spread over the remainder of his/her lifetime (and also covering the cost of dependants benefits after his/her death).

(iii) The total change in value (B) in the last column of the table above reflects the following elements:
1. changes to the economic and demographic assumptions underlying the transfer value basis over the year
2. any increases in pensionable salary received during the year
3. the completion of another year of pensionable service during the year
4. the directors are a year closer to drawing their pensions, which increases their pension value (all other things being equal).

The change in the amount of the transfer values over the year includes the effect of fluctuations in factors that are beyond the control of the company and its directors, such as stockmarket movements and long-term interest rates.

(iv) The accrued pension shown is that which would be paid annually on retirement based upon service to the end of the year. Members of the company s schemes have the option of paying additional voluntary contributions; neither the contributions nor the resulting benefits are included in the above table.

(v) Directors who joined the UK pension scheme on or after 1 June 1989 are subject to the earnings cap, introduced in the Finance Act 1989. Pension entitlements which cannot be provided through the company s approved schemes, due to the earnings cap, are provided through unapproved pension arrangements, details of which are included in the Remuneration Report. The pension benefits disclosed above include approved and unapproved pension arrangements.

(vi) The increase in UK accrued pension during the year excludes the increase due to RPI inflation as measured at December 2004 (3.5%).

(vii) The value of directors UK entitlements has been calculated on the basis of actuarial advice in accordance with Actuarial Guidance note GN11, in two parts: the approved element being based upon the normal cash equivalent transfer value assumptions; the unapproved element being calculated in line with FRS 17 assumptions.

The value of the US director s entitlement has been calculated in line with FRS 17 assumptions.

(viii) Transferred-in plan benefits represent pension rights accrued in respect of previous employments. The accrued pension shown at the end of the year includes transferred-in benefits.

(ix) The total liabilities, calculated on a FRS17 basis, arising in relation to UK unapproved benefits for all executives and senior employees for service in the year to 31 March 2005 was £1,520,900 (2004 £934,100). This figure relates only to the cost of benefits accruing over the year but does not include any finance items. It therefore differs from the full FRS17 charge for unapproved benefits over the same period.

(x) All benefits above are provided on a defined benefit basis.

(xi) Judi Johansen may also be eligible to participate in the company s post-retirement healthcare plans, providing that she meets the eligibility criteria at the time she terminates or retires from the company. Currently that criteria is termination after age 55 with five of more years of service.

Table 50

Ø Directors Interests in ScottishPower Shares

	Ordinary shares		**Share options (Executive[1])**		**Share options (Sharesave)**		**Long Term Incentive Plan**			
	31.3.05	**1.4.04 (or date of appointment if later)**	**31.3.05**	**1.4.04 (or date of appointment if later)**	**31.3.05**	**1.4.04 (or date of appointment if later)**	**31.3.05**		**1.4.04 (or date of appointment if later)**	
							****Vested**	***Potential**	****Vested**	***Potential**
Charles Miller Smith	11,000	11,000								
Vicky Bailey (appointed 1 June 2004)										
Euan Baird	114,363	114,363								
Donald Brydon	3,000	3,000								
Philip Carroll	4,000	4,000								
Nolan Karras	42,446	39,297								
Nick Rose	5,395	5,128								

Nancy Wilgenbusch (appointed 1 June 2004)	508									
Ian Russell	128,280	127,376	1,206,427	844,192	5,290	5,290	58,047	367,006	21,217	323,243
Charles Berry	41,712	23,506	628,407	422,884	2,941	2,941		195,279	11,968	161,734
Judi Johansen	103,331	88,960	496,500	898,000				166,289		86,627
Simon Lowth	17,710		220,937					82,851		
David Nish	36,415	13,964	738,171	517,234		2,509		230,230	10,880	197,602

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None of the directors has an interest in ordinary shares which is greater than 1% of the issued share capital of the company.

[1] Includes options granted under the Executive Share Option Plan 2001 and, where applicable, the PacifiCorp Stock Incentive Plan.
* These shares represent, in each case, the maximum number of shares which the directors may receive, dependent on the satisfaction of performance criteria as approved by shareholders in connection with the Long Term Incentive Plan.

** These shares represent the number of shares the directors are entitled to receive when the LTIP award becomes exercisable calculated according to the performance criteria measured over the three-year performance period.

These shares include the number of shares which the directors hold in the Employee Share Ownership Plan, shown below.

	Free shares		Partnership shares		Matching shares		Dividend shares		Total	
	31.3.05	1.4.04	31.3.05	1.4.04	31.3.05	1.4.04	31.3.05	1.4.04	31.3.05	1.4.04
Ian Russell	50	50	1,580	1,210	1,580	1,210	430	266	3,640	2,736
Charles Berry	50	50	1,580	1,210	1,580	1,210	430	266	3,640	2,736
David Nish	50	50	1,580	1,210	1,580	1,210	430	266	3,640	2,736

Between 31 March 2005 and 19 May 2005, Ian Russell, Charles Berry and David Nish each acquired 60 Partnership shares and 60 Matching shares as part of the regular monthly transactions of the Employee Share Ownership Plan; and Judi Johansen, Nolan Karras and Nancy Wilgenbusch acquired 394.0877, 30.8167 and 30.8167 ScottishPower ADSs (1,577, 123 and 123 Ordinary shares) respectively as part of the PacifiCorp Compensation Reduction Plan. Additionally, 1,225 ADSs (4,900 ordinary shares) held by Judi Johansen in the form of Unvested Restricted Stock in the PacifiCorp Stock Incentive Plan, vested and became non-forfeitable on 24 April 2005 and, in accordance with the deferral election executed by Judi Johansen, were all immediately transferred into the PacifiCorp Compensation Reduction Plan. Otherwise, there have been no changes to the directors interests between 31 March 2005 and 19 May 2005.

Table 51

Ø Directors Interests in Performance and Other Share Plans at 31 March 2005

	1 April 2004 (or date of appointment if later)	Granted	Exercised	Lapsed#	31 March 2005	Option exercise price (pence)	Date exercised	Market price at date of exercise (pence)	Date from which exercisable	Expiry date
Long Term Incentive Plan										
Ian Russell	21,217				21,217	nil			05 May 04	04 May 07
	92,075			55,245	36,830	nil			04 May 04	03 May 08
	101,600				101,600	nil			02 May 05	01 May 09
	129,568				129,568	nil			10 May 06	09 May 10
		135,838			135,838	nil			27 May 07	26 May 11
	344,460	135,838		55,245	425,053					
Charles Berry	11,968		11,968			nil	09 Jun 04	392.5	05 May 04	04 May 07
	43,526		17,410	26,116		nil	09 Jun 04	392.5	04 May 04	03 May 08
	55,418				55,418	nil			02 May 05	01 May 09
	62,790				62,790	nil			10 May 06	09 May 10
		77,071			77,071	nil			27 May 07	26 May 11

	173,702	77,071	29,378	26,116	195,279					
Judi Johansen	36,794				36,794	nil			02 May 05	01 May 09
	49,833				49,833	nil			10 May 06	09 May 10
		79,662			79,662	nil			27 May 07	26 May 11
	86,627	79,662			166,289					
Simon Lowth		82,851			82,851	nil			27 May 07	26 May 11
		82,851			82,851					
David Nish	10,880		10,880			nil	25 Nov 04	394.3	05 May 04	04 May 07
	50,223		20,089	30,134		nil	25 Nov 04	394.3	04 May 04	03 May 08
	64,655				64,655	nil			02 May 05	01 May 09
	82,724				82,724	nil			10 May 06	09 May 10
		82,851			82,851	nil			27 May 07	26 May 11
	208,482	82,851	30,969	30,134	230,230					

During the year, the performance period for the awards granted under the Long Term Incentive Plan on 4 May 2001 ended and, on the basis of the company s total shareholder return, 40% of shares under awards vested. These awards became exercisable either immediately or at any other time until the seventh anniversary of grant. The market price of ScottishPower ordinary shares at the date of grant of these awards was 432.35 pence and on 27 May 2004, being the date of vesting, was 396.75 pence. Long Term Incentive Plan awards granted before 2001 became exercisable on the fourth anniversary of grant. Awards granted in 2001 and subsequently became exercisable on the third anniversary of grant, as approved by shareholders.

Awards granted during the year were granted for no consideration. The market value of a ScottishPower shares at the date of grant was 396.75 pence.

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Remuneration Report of the Directors

Table 51

Ø Directors Interests in Performance and Other Share Plans at 31 March 2005 continued

	1 April 2004 (or date of appointment if later)	Granted	Exercised	Lapsed	31 March 2005	Option exercise price (pence)	Date exercised	Market price at date of exercise (pence)	Date from which exercisable	Expiry date
Executive Share Option Plan 2001										
Ian Russell	227,743				227,743	483.0			21 Aug 04	21 Aug 11
	270,935				270,935	406.0			02 May 05	02 May 12
	345,514				345,514	376.3			10 May 06	10 May 13
		362,235			362,235	389.3			27 May 07	27 May 14
	844,192	362,235			1,206,427					
Charles Berry	107,660				107,660	483.0			21 Aug 04	21 Aug 11
	147,783				147,783	406.0			02 May 05	02 May 12
	167,441				167,441	376.3			10 May 06	10 May 13
		205,523			205,523	389.3			27 May 07	27 May 14
	422,884	205,523			628,407					
Judi Johansen	61,824				61,824	311.5			02 May 05	02 May 12
	61,824		61,824			311.5	01 Jun 04	398.8**	02 May 03	02 May 12
	61,824		61,824			311.5	01 Jun 04	398.8**	02 May 04	02 May 12
	61,828				61,828	311.5			02 May 05	02 May 12
	81,968		81,964		4	322.8	01 Jun 04	398.8**	10 May 04	10 May 13
	81,964				81,964	322.8			10 May 05	10 May 13
	81,968				81,968	322.8			10 May 06	10 May 13
		208,912			208,912	379.9			27 May 07	27 May 14
	493,200	208,912	205,612		496,500					
Simon Lowth		220,937			220,937	389.3			27 May 07	27 May 14
		220,937			220,937					
David Nish	124,223				124,223	483.0			21 Aug 04	21 Aug 11
	172,413				172,413	406.0			02 May 05	02 May 12
	220,598				220,598	376.3			10 May 06	10 May 13
		220,937			220,937	389.3			27 May 07	27 May 14
	517,234	220,937			738,171					
PacifiCorp Stock Incentive Plan										
Judi Johansen	76,464		76,464			331.5	01 Jun 04	398.8**	25 Jan 02	25 Jan 11
	76,468		76,468			331.5	01 Jun 04	398.8**	25 Jan 03	25 Jan 11
	76,468		76,468			331.5	01 Jun 04	398.8**	25 Jan 04	25 Jan 11
	22,464		22,464			339.9	01 Jun 04	398.8**	24 Apr 02	24 Apr 11
	76,468		76,468			339.9	01 Jun 04	398.8**	24 Apr 03	24 Apr 11
	76,468		76,468			339.9	01 Jun 04	398.8**	24 Apr 04	24 Apr 11
	404,800		404,800							
Sharesave Scheme										
Ian Russell	5,290				5,290	301.0			01 Sep 08	28 Feb 09
	5,290				5,290					
Charles Berry	2,941				2,941	323.0*			01 Sep 05	28 Feb 06
	2,941				2,941					
David Nish	2,509		2,509			386.0*	17 Jan 05	412.5	01 Sep 04	28 Feb 05
	2,509		2,509							

* Denotes options granted under a three-year scheme.

** The exercise of Executive Share Option Plan 2001 options by Judi Johansen on 1 June 2004 was over 30,912 ADSs at US$23.55 per ADS and 20,491 ADSs at US$24.40 per ADS. The exercise of PacifiCorp Stock Incentive Plan options by Judi Johansen on 1 June 2004 was over 57,350 ADSs at US$25.06 per ADS and 43,850 ADSs at US$25.70 per ADS. On 1 June 2004 the market value of a ScottishPower ADS was US$29.51.

(i) The market price of the shares at 31 March 2005 was 409.0 pence and the range during 2004/05 was 377.5 pence to 446.75 pence.

(ii) The Long Term Incentive Plan makes annual awards to acquire shares in ScottishPower at nil or nominal cost to the plan participants up to a maximum value equal to 75% of base salary. The award will vest only if the Remuneration Committee is satisfied that certain performance measures related to the sustained underlying financial performance of the company and sustained underlying performance in certain Customer Service Standards are achieved over a period of three financial years commencing with the financial year preceding the date an award is made. Assuming that such targets have been achieved, the number of shares that can be acquired under awards granted before May 2001 was dependent upon how the company ranked in terms of its total shareholder return performance over a three-year period, in comparison to the constituent companies of the FTSE 100 index and the Electricity and Water sectors. A percentage of each half of the award would vest depending upon the company s ranking within each of the comparator groups. For awards granted in May 2001 and subsequently, the company s total shareholder return performance is compared over a three-year period against an international comparator group of major energy companies. A percentage of the award vests dependent upon the company s ranking within the comparator group. The plan participant may acquire the shares in respect of the percentage of the award which has vested at any time after the third year (or fourth year for awards granted before 2001) up to the seventh year after the grant of the award. No dividends accrue to participants prior to vesting.

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(iii) The company has granted options annually for the last four years under the Executive Share Option Plan 2001 to relevant executives and senior managers at nil or nominal cost. The exercise of options granted to UK executives and senior managers, and of those granted to Judi Johansen since her appointment to the board of ScottishPower, is subject to the performance criterion that the percentage increase in the company s annualised earnings per share be at least 3% (adjusted for any increase in the RPI). This criterion is assessed at the end of the third financial year, the first year being the financial year starting immediately before the date of grant. If the criterion is not satisfied over this period, it is tested again at the end of the fourth financial year. If the criterion is not satisfied over this period, it is tested again at the end of the fifth financial year. If the criterion is not satisfied over this period, then the options lapse. The exercise of options granted to US participants is not normally subject to the satisfaction of performance criteria, and they normally become exercisable as follows: one-third of the options from the first anniversary of the date of grant, a further one-third from the second anniversary and the final one-third from the third anniversary of the date of grant. In 2002, an additional, conditional share option award was made to some senior managers, including Judi Johansen, under the Executive Share Option Plan 2001. The exercise of these additional, conditional options is subject to the same exercise period and performance criterion as options granted to UK participants.

(iv) On 21 August 2004, options granted on 21 August 2001 to Ian Russell, Charles Berry and David Nish under the Executive Share Option Plan 2001 vested following testing against the performance criterion and became exercisable immediately. The market price of ScottishPower ordinary shares on 21 August 2001 and 20 August 2004 (being the last trading date before 21 August 2004) was 475.99 pence and 390.25 pence respectively.

(v) Options granted to Judi Johansen under the PacifiCorp Stock Incentive Plan and the Executive Share Option Plan 2001 are granted over ScottishPower ADSs. For the purposes of the above table, these options, in the case of Judi Johansen, have been converted to ordinary shares as follows: one ScottishPower ADS equals four ScottishPower ordinary shares. The US$ ADS option prices were converted so that they may be represented in terms of ScottishPower ordinary shares. The prices were further converted at the closing exchange rate on 31 March 2005 of £1 = $1.890 so as to be quoted in pence in the above table.

61,824 options granted to Judi Johansen on 2 May 2002 and a further 81,968 options granted on 10 May 2003 under the Executive Share Option Plan 2001 became exercisable on 2 May 2004 and 10 May 2004 respectively. The market price of ScottishPower ordinary shares on 2 May 2002, 9 May 2003 (being the last trading date before 10 May 2003), 30 April 2004 (being the last trading date before 2 May 2004) and 10 May 2004 was 411.5 pence, 376.25 pence, 383.25 pence and 378.00 pence respectively. 76,468 options granted on 24 April 2001 to Judi Johansen under the PacifiCorp Stock Incentive Plan became exercisable on 24 April 2004. The market price of ScottishPower ordinary shares on 24 April 2001 and 23 April 2004 (being the last trading date before 24 April 2004) was 477.00 pence and 391.75 pence respectively.

(vi) The option price for Sharesave options is calculated by reference to the middle-market quotation on the day immediately preceding the date of invitation and discounted by 20% in accordance with the Inland Revenue rules for such schemes.

The number of options granted to a director under the Sharesave Scheme is calculated by reference to the total amount which the director agrees to save for a period of either three or five years under an Inland Revenue approved savings contract, subject to a current maximum.

(vii) Total gains made on exercise of directors share options and awards during the year were £623,361 (2004 £60,442). The conversion rate for gains made by Judi Johansen is £1 = $1.846, being the average exchange rate during the year.

Approved by the Board and signed on its behalf by

Nolan Karras Chairman of the Remuneration Committee

24 May 2005

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Directors Responsibility for the Accounts

The directors are required by law to prepare Accounts for each financial year and to present them annually to the company s members at the Annual General Meeting. The Accounts, of which the form and content are prescribed by the Companies Act 1985 and applicable accounting standards, must give a true and fair view of the state of affairs of the company and of the group as at the end of the financial year, and of the group s profit or loss for the period.

The directors confirm that suitable Accounting Policies have been used and applied consistently, and that reasonable and prudent judgements and estimates have been made in the preparation of the Accounts for the year ended 31 March 2005. The directors also confirm that applicable accounting standards have been followed and that the Accounts have been prepared on the going concern basis.

The directors are responsible for maintaining proper accounting records and sufficient internal controls to safeguard the assets of the company and of the group and to prevent and detect fraud or any other irregularities.

Auditors

PricewaterhouseCoopers LLP, the company s auditors, have expressed their willingness to continue in office and a resolution for their re-appointment will be proposed at the Annual General Meeting.

Report of the Directors

The Report of the Directors, comprising the statements and reports on pages 2 to 106 of this Annual Report & Accounts, has been approved by the Board and signed on its behalf by

Andrew Mitchell Secretary

24 May 2005

Safe Harbor Statement

Cautionary Statement for Purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995

Some statements contained herein may include statements regarding our assumptions, projections, expectations or beliefs about future events. These statements are intended as Forward-Looking Statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. All statements with respect to us, our corporate plans, future financial condition, future results of operations, future business plans, strategies, objectives and beliefs and other statements that are not historical facts are forward looking. Statements containing the words may , will , expect , anticipate , believe , intend , estimate , continue , plan , project , target , on track to , strategy , aim , seek , will meet or other similar words are also forward-looking. These statements are based on our management s assumptions and beliefs in light of the information available to us. These assumptions involve risks and uncertainties which may cause the actual results, performance or achievements to be materially different from any future results,

Ø the success of reorganizational and cost-saving or other strategic efforts, including the proposed sale of PacifiCorp;

Ø any regulatory changes (including changes in environmental regulations) that may increase the operating costs of the group, may require the group to make unforeseen capital expenditures or may prevent the regulated business of the group from achieving acceptable returns;

Ø the outcome of general rate cases and other proceedings conducted by regulatory commissions;

Ø the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings;

performance or achievements expressed or implied by such forward-looking statements.

ScottishPower wishes to caution readers, and others to whom forward-looking statements are addressed, that any such forward-looking statements are not guarantees of future performance and that actual results may differ materially from estimates in the forward-looking statements. ScottishPower undertakes no obligation to revise these forward-looking statements to reflect events or circumstances after the date hereof. Important factors that may cause results to differ from expectations include, for example:

Ø future levels of industry generation and supply, demand and pricing, political stability, competition and economic growth in the relevant areas in which the group has operations;

Ø the availability of acceptable fuel at favorable prices;

Ø weather and weather-related impacts;

Ø the availability of operational capacity of plants;

Ø adequacy and accuracy of load and price forecasts that could impact the hedging strategy and costs to balance electricity load and supply;

Ø timely and appropriate completion of the Request for Proposals process, unanticipated construction delays, changes in costs, receipt of required permits and authorizations, and other factors that could affect future generation plants and infrastructure additions;

Ø the impact of interest rates and investment performance on pension and post-retirement expense;

Ø the impact of new accounting pronouncements on results of operations; and

Ø development and use of technology, the actions of competitors, natural disasters and other changes to business conditions.

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Accounting Policies

and Definitions

Definitions

Business segment definitions

ScottishPower defines business segments for management reporting purposes based on a combination of factors, principally differences in products and services and the regulatory environment in which the businesses operate.

Business segments have been included under either continuing operations or discontinued operations as appropriate.

The business segments of the group are defined as follows:

Continuing operations

United Kingdom

UK Division Integrated Generation and Supply The generation of electricity from the group s own power stations, the purchase of external supplies of coal and gas for the generation of electricity, the purchase of external supplies of electricity and gas for sale to customers, together with related billing and collection activities, gas storage, sale of gas to industrial and domestic customers and the sale of electricity to electricity suppliers, in Scotland, Northern Ireland, England & Wales and full participation in the New Electricity Trading Arrangements (NETA) in England & Wales. NETA was replaced by the British Electricity Trading and Transmission Arrangements (BETTA) with effect from 1 April 2005.

Infrastructure Division Power Systems The transmission and distribution businesses within the group s authorised area of Scotland and the distribution business of Manweb operating in Merseyside and North Wales.

United States

PacifiCorp A vertically-integrated electric utility that includes the generation, transmission and distribution and sale of electricity to retail, industrial and commercial customers in portions of six western states; Utah, Oregon, Wyoming, Washington, Idaho and California. The operations also include wholesale energy sales and purchase transactions with various entities. The state regulatory commissions and Federal Energy Regulatory Commission (FERC) regulate the retail and wholesale operations. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining facilities and services and environmental remediation.

PPM Energy (PPM) The competitive energy development, origination and marketing business serving wholesale customers in North American markets. Electricity products and services are provided from gas generation and renewable wind generation resources located in the western and mid-western US. Natural gas storage and hub services are provided from gas storage facilities located in Canada and the US.

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Accounts 2004/05

Discontinued operations

United Kingdom

Southern Water The provision of water and wastewater services in the south east of England, together with related billing and collection activities. The disposal of the Southern Water business was completed on 23 April 2002.

Revenue cost definitions

Cost of sales The cost of sales for the group, excluding Southern Water, reflect the direct costs of the generation and purchase of electricity and the purchase and transportation of natural gas.

For Southern Water, cost of sales represented the cost of extracting water from underground and raw water surface reservoirs and of its treatment and supply to customers and the collection of wastewater and its treatment and disposal.

Transmission and distribution costs The cost of transmitting units of electricity from the power stations through the transmission and distribution networks to customers. It includes the costs of metering, billing and debt collection. This heading is considered more appropriate to the electricity industry than the standard Companies Act heading of distribution costs.

Administrative expenses The indirect costs of businesses, the costs of corporate services, property rates, goodwill amortisation and impairment of goodwill.

Other definitions

Company or ScottishPower Scottish Power plc.

Basis of consolidation

The group Accounts include the Accounts of the company and its subsidiary undertakings together with the group s share of results and net assets of associated undertakings and joint ventures.

For commercial reasons certain subsidiaries have a different year end. The consolidation includes the Accounts of these subsidiaries as adjusted for material transactions in the period between the year ends and 31 March.

Use of estimates

The preparation of Accounts in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the Accounts and the reported amounts of revenues and expenses during the reporting period. Actual results can differ from those estimates.

Turnover

Turnover comprises the sales value of energy and other services supplied to customers during the year and excludes Value Added Tax and intra-group sales. Turnover from the sale of energy is the value of units supplied during the year and includes an estimate of the value of units supplied to customers between the date of their last meter reading and the year end, based on external data supplied by the electricity and gas market settlement processes. Prior to the disposal of Southern Water in April 2002, turnover also included the sales value of water and wastewater services.

Interest

Interest on the funding attributable to major capital projects is capitalised gross of tax relief during the period of construction and written off as part of the total cost over the operational life of the asset. All other interest payable and receivable is reflected in the profit and loss account as it arises.

Group Scottish Power plc and its consolidated subsidiaries.

Associated undertakings Entities in which the group holds a long-term participating interest and exercises significant influence.

Joint ventures Entities in which the group holds a long-term interest and shares control with another company external to the group.

Subsidiary undertakings Entities in which the group holds a long-term controlling interest.

Accounting Policies

Basis of accounting

The Accounts have been prepared under the historical cost convention, modified to include the revaluation of certain tangible fixed assets, and in accordance with applicable accounting standards in the UK and, except for the accounting policy for Commodity contracts , described below, comply with the requirements of the Companies Act 1985. Further details explaining this departure are contained in Note 20(i) to the Accounts.

Financial instruments

Debt instruments All borrowings are stated at the fair value of consideration received after deduction of issue costs. The issue costs and interest payable on bonds are charged to the profit and loss account at a constant rate over the life of the bond. Premiums and discounts arising on the early repayment of borrowings are recognised in the profit and loss account as incurred and received.

Interest rate swaps/Forward rate agreements These are used to manage debt interest rate exposures. Amounts payable or receivable in respect of these agreements are recognised as adjustments to interest expense over the period of the contracts. The cash flows from, and gains and losses arising on terminations of, these contracts are recognised as returns on investments and servicing of finance. Where associated debt is not retired in conjunction with the termination of an interest swap, gains and losses are deferred and are amortised to interest expense over the remaining life of the associated debt to the extent that such debt remains outstanding.

Interest rate caps/Swaptions/Options Premiums received and payable on these contracts are amortised over the period of the contracts and are disclosed as interest income and expense. The accounting for interest rate caps and swaptions is otherwise in accordance with interest rate swaps detailed above.

Cross-currency interest rate swaps These are used both to hedge foreign exchange and interest rate exposures arising on foreign currency debt and to hedge overseas net investment. Where used to hedge debt issues, the debt is recorded at the hedge contracted rate and accounting is otherwise in accordance with interest rate swaps detailed above. Where used to hedge overseas net investment, spot gains or losses are recorded on the balance sheet and in the statement of total recognised gains and losses, with interest recorded in the profit and loss account. The cash flows from, and gains and losses arising on the termination, repricing or maturity of, cross-currency interest rate swaps hedging overseas net investments are recognised as returns on investments and servicing of finance to the extent they relate to interest and as financing to the extent they represent spot gains or losses.

Forward contracts The group enters into forward contracts for the purchase and/or sale of foreign currencies in order to manage its exposure to fluctuations in currency rates and to hedge overseas net investment. The cash flows from forward purchase contracts are classified in a manner consistent with the underlying nature of the hedged transaction. Hence, unrealised gains and losses on contracts hedging forecast transactions are not accounted for until the maturity of the contract. Foreign currency debtors and creditors that are hedged with forward contracts are translated at the contracted rate at the balance sheet date. Spot gains or losses on hedges of the overseas net investments are recorded on the balance sheet and in the statement of total recognised gains and losses with the interest rate differential reflected in the profit and loss account.

Hydroelectric and temperature hedges These instruments are used to hedge fluctuations in weather and temperature in the US. On a periodic basis, the group estimates and records a gain or loss in the profit and loss account corresponding to the total expected future cash flows from these contracts.

Commodity contracts Where there is no physical delivery associated with commodity contracts, they are recorded at fair value on the balance sheet and movements reflected through the profit and loss account. Gas and electricity forwards and futures are undertaken for hedging and proprietary trading purposes. Where the instrument is a hedge, the fair values are initially reflected on the balance sheet and subsequently reflected through the profit and loss account to match the recognition of the hedged item. Where the instrument is for proprietary trading the fair values are reflected through the profit and loss account. Recognition of unrealised gains on commodity contracts in the profit and loss account is not in accordance with the provisions of the Companies Act 1985. The directors consider that compliance with these requirements would lead to the accounts failing to give a true and fair view of the results of the group. Further details of the effect of this accounting policy are provided in Note 20(i) to the Accounts.

Taxation

In accordance with Financial Reporting Standard (FRS) 19 Deferred tax , full provision is made for deferred tax on a non-discounted basis.

Intangible assets

Long-term gas purchase contracts acquired as part of acquisitions are capitalised, as intangible fixed assets, separately from goodwill, provided their fair value can be measured reliably on initial recognition. As these contracts do not have readily ascertainable market values, fair value is limited to the amount that does not create or increase any negative goodwill, in accordance with FRS 10. These intangible fixed assets are amortised over the period of the contracts.

Goodwill

Purchased goodwill represents the excess of the fair value of the purchase consideration over the fair value of the net assets acquired. Goodwill arising from acquisitions prior to 31 March 1998 was written off against reserves. On disposal of trading entities, the goodwill previously included in reserves is charged to the profit and loss account matched by an equal credit to reserves. Goodwill arising on acquisitions since 1 April 1998 has been capitalised and amortised through the profit and loss account over its estimated useful economic life. Goodwill arising on overseas acquisitions is regarded as a currency asset and is retranslated at the end of each period at the closing rate of exchange.

The carrying value of goodwill is reviewed for impairment in periods if events or changes in circumstances indicate the carrying value may not be recoverable. Impairment losses are recognised in the period in which they are identified.

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Accounts 2004/05

Tangible fixed assets

Tangible fixed assets are stated at cost or valuation and are generally depreciated on the straight line method over their estimated operational lives. Tangible fixed assets include capitalised employee, interest and other costs which are directly attributable to construction of fixed assets.

Land is not depreciated except in the case of mines (see below). The main depreciation periods used by the group are as set out below.

	Years
Coal, oil-fired, gas and other generating stations	22 45
Hydro plant and machinery	20 100
Other buildings	40
Transmission and distribution plant	20 75
Towers, lines and underground cables	40 60
Vehicles, computer software costs, miscellaneous equipment and fittings	3 40

Composite depreciation rates applied to the group s regulated utility plants in the US for the year ended 31 March 2005 were 3.0% (2004 3.0%, 2003 3.2%).

The carrying values of tangible fixed assets are reviewed for impairment in periods if events or changes in circumstances indicate the carrying value may not be recoverable. For those assets with estimated remaining useful economic lives of more than 50 years, impairment reviews are undertaken annually. Impairment losses are recognised in the period in which they are identified.

Mine reclamation and closure costs Provision is made for mine reclamation and closure costs when an obligation arises out of events prior to the year end. The amount recognised is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. A corresponding tangible fixed asset is also created of an amount equal to the provision. This asset, together with the cost of the mine, is subsequently depreciated on a unit of production basis. The unwinding of the discount is included within net interest and similar charges.

Decommissioning costs Provision is made for the estimated decommissioning costs at the end of the producing lives of the group s power stations on a discounted basis. Capitalised decommissioning costs are depreciated over the useful lives of the related assets. The unwinding of the discount is included within net interest and similar charges.

Leased assets

As lessor Rentals receivable under finance leases are allocated to accounting periods to give a constant periodic rate of return on the net cash investment in the lease in each period. The amounts due from lessees under finance leases are recorded in the balance sheet as a debtor at the amount of the net investment in the lease after making provisions for bad and doubtful rentals receivable.

Investments

Investments in subsidiary and associated undertakings and joint ventures are stated in the balance sheet of the parent company at cost, or nominal value of shares issued as consideration where applicable, less provision for any impairment in value. The group profit and loss account includes the group s share of the operating profits less losses, net interest charge and taxation of associated undertakings and joint ventures. The group balance sheet includes the investment in associated undertakings and joint ventures at the group s share of their net assets. Other fixed asset investments are carried at cost less provision for impairment in value.

Own shares held under trust

Own shares held under trust have been deducted in arriving at shareholders funds in accordance with Urgent Issues Task Force Abstract 38 Accounting for ESOP trusts (UITF 38). Purchases and sales of own shares are disclosed as changes in shareholders funds.

Revised UITF 17 Employee share schemes (Revised UITF 17) requires that the profit and loss account charge be determined as the intrinsic value of the share options granted.

The group has taken advantage of the exemption within Revised UITF Abstract 17 not to apply its requirements to Inland Revenue approved savings-related share option schemes and equivalent overseas schemes.

Long Term Incentive Plan (LTIP)

As lessee Assets leased under finance leases are capitalised and depreciated over the shorter of the lease periods and the estimated operational lives of the assets. The interest element of the finance lease repayments is charged to the profit and loss account in proportion to the balance of the capital repayments outstanding. Rentals payable under operating leases are charged to the profit and loss account on a straight line basis.

Shares in the company purchased for the LTIP are held under trust. The cost of awards made by the trust under the LTIP, being the difference between the fair value of the shares and the option price at the date of grant, is taken to the profit and loss account on a straight line basis over the period in which performance is measured.

Stocks

Stocks are valued at the lower of average cost and net realisable value.

US regulatory assets

Statement of Financial Accounting Standard No. 71 Accounting for the Effects of Certain Types of Regulation (FAS 71) establishes US GAAP for utilities in the US whose regulators have the power to approve and/or regulate rates that may be charged to customers. FAS 71 provides that regulatory assets may be capitalised if it is probable that future revenue in an amount at least equal to the capitalised costs will result from the inclusion of that cost in allowable costs for ratemaking purposes. Due to the different regulatory environment, no equivalent GAAP applies in the UK.

Under UK GAAP, the group s policy is to recognise regulatory assets established in accordance with FAS 71 only where they comprise rights or other access to future economic benefits which have arisen as a result of past transactions or events which have created an obligation to transfer economic benefits to a third party. Measurement of the past transaction or event and hence the regulatory asset, is determined in accordance with UK GAAP.

Grants and contributions

Capital grants and customer contributions in respect of additions to fixed assets are treated as deferred income and released to the profit and loss account over the estimated operational lives of the related assets.

Pensions

The group provides pension benefits through both defined benefit and defined contribution arrangements. The regular cost of providing pensions and related benefits and any variations from regular cost arising from the actuarial valuations for defined benefit schemes are charged to the profit and loss account over the expected remaining service lives of current employees following consultations with the actuary. Any difference between the charge to the profit and loss account and the actual contributions paid to the pension schemes is included as an asset or liability in the balance sheet. Payments to defined contribution schemes are charged against profits as incurred.

Post-retirement benefits other than pensions

Certain additional post-retirement benefits, principally healthcare benefits, are provided to eligible retirees within the group s US businesses. The estimated cost of providing such benefits is charged against profits on a systematic basis over the employees working lives within the group.

Environmental liabilities

Provision for environmental liabilities is made when expenditure on remedial work is probable and the group is obliged, either legally or constructively through its environmental policies, to undertake such work. Where the amount is expected to be incurred over the long-term, the amount recognised is the present value of the estimated future expenditure and the unwinding of the discount is included within net interest and similar charges.

Foreign currencies

Group The results and cash flows of overseas subsidiaries are translated to sterling at the average rate of exchange for each quarter of the financial year. The net assets of such subsidiaries and the goodwill arising on their acquisition are translated to sterling at the closing rates of exchange ruling at the balance sheet date. Exchange differences which relate to the translation of overseas subsidiaries and of matching foreign currency borrowings and derivatives are taken directly to group reserves and are shown in the statement of total recognised gains and losses.

Company Transactions in foreign currencies are recorded at the rate ruling at the date of the transaction. At the year end, monetary assets and liabilities denominated in foreign currencies are translated at the rate of exchange ruling at the balance sheet date or, where applicable, at the hedged contracted rate. Any gain or loss arising on the restatement of such balances is taken to the profit and loss account.

Exchange rates

The exchange rates applied in the preparation of the Accounts were as follows:

	Year ended 31 March		
	2005	2004	2003
Average rate for quarters ended:			
30 June	**$1.81/£**	$1.62/£	$1.46/£
30 September	**$1.82/£**	$1.61/£	$1.55/£
31 December	**$1.87/£**	$1.71/£	$1.57/£
31 March	**$1.89/£**	$1.84/£	$1.60/£
Closing rate as at 31 March	**$1.89/£**	$1.84/£	$1.58/£

A glossary of terms used in the Accounts and their US equivalents is set out on page 172.

Accounts 2004/05

Ø Group Profit and Loss Account

for the years ended 31 March 2005, 31 March 2004 and 31 March 2003

		Year ended 31 March				
		Continuing operations and Total 2005	Continuing operations and Total 2004	Continuing operations 2003	Discontinued operations 2003	Total 2003
	Notes	**£m**	£m	£m	£m	£m
Turnover: group and share of joint ventures and associates		**6,877.4**	5,828.9	5,273.1	26.7	5,299.8
Less: share of turnover in joint ventures		**(27.4)**	(31.0)	(25.2)		(25.2)
Less: share of turnover in associates		**(1.2)**	(0.8)	(0.8)		(0.8)
Group turnover	1	**6,848.8**	5,797.1	5,247.1	26.7	5,273.8
Cost of sales		**(4,567.2)**	(3,630.6)	(3,215.4)	(11.4)	(3,226.8)
Gross profit		**2,281.6**	2,166.5	2,031.7	15.3	2,047.0
Transmission and distribution costs		**(606.2)**	(544.5)	(512.6)		(512.6)
Administrative expenses before goodwill amortisation and exceptional item		**(511.3)**	(498.2)	(474.2)	(1.3)	(475.5)
Goodwill amortisation		**(117.5)**	(128.0)	(139.0)		(139.0)
Exceptional item impairment of goodwill	4	**(927.0)**				
Administrative expenses		**(1,555.8)**	(626.2)	(613.2)	(1.3)	(614.5)
Other operating income		**33.0**	26.8	26.0		26.0
Operating profit before goodwill amortisation and exceptional item		**1,197.1**	1,150.6	1,070.9	14.0	1,084.9
Goodwill amortisation		**(117.5)**	(128.0)	(139.0)		(139.0)
Exceptional item impairment of goodwill	4	**(927.0)**				
Operating profit	1, 2	**152.6**	1,022.6	931.9	14.0	945.9
Share of operating profit in joint ventures		**2.2**	7.3	4.8		4.8
Share of operating profit in associates		**3.8**	0.3	0.4		0.4
Profit on ordinary activities before interest		**158.6**	1,030.2	937.1	14.0	951.1
Net interest and similar charges						
Group		**(183.7)**	(232.3)	(245.9)	(3.0)	(248.9)
Joint ventures		**(4.2)**	(5.8)	(5.4)		(5.4)
	5	**(187.9)**	(238.1)	(251.3)	(3.0)	(254.3)
Profit on ordinary activities before goodwill amortisation, exceptional item and taxation		**1,015.2**	920.1	824.8	11.0	835.8
Goodwill amortisation		**(117.5)**	(128.0)	(139.0)		(139.0)
Exceptional item impairment of goodwill	4	**(927.0)**				
(Loss)/profit on ordinary activities before taxation		**(29.3)**	792.1	685.8	11.0	696.8
Taxation						
Group		**(272.3)**	(247.3)	(205.8)	(3.4)	(209.2)
Joint ventures		**(0.2)**	(1.0)	0.3		0.3
Associates		**(1.6)**	(0.1)	(0.1)		(0.1)
	6	**(274.1)**	(248.4)	(205.6)	(3.4)	(209.0)
(Loss)/profit after taxation		**(303.4)**	543.7	480.2	7.6	487.8
Minority interests (including non-equity)	27	**(4.7)**	(5.8)	(5.2)		(5.2)
(Loss)/profit for the financial year		**(308.1)**	537.9	475.0	7.6	482.6

Dividends	8	**(412.6)**	(375.1)	(529.5)		(529.5)
(Loss)/profit retained	26	**(720.7)**	162.8	(54.5)	7.6	(46.9)
(Loss)/earnings per ordinary share	7	**(16.83)p**	29.40p	25.76p	0.41p	26.17p
Adjusting items goodwill amortisation		**6.42p**	7.00p	7.54p		7.54p
exceptional item impairment of goodwill		**50.63p**				
Earnings per ordinary share before goodwill amortisation and exceptional item	7	**40.22p**	36.40p	33.30p	0.41p	33.71p
Diluted (loss)/earnings per ordinary share	7	**(16.83)p**	28.83p			26.11p
Adjusting item effect of anti-dilutive shares		**1.42p**				
		(15.41)p	28.83p			26.11p
Adjusting items goodwill amortisation		**6.10p**	6.77p			7.52p
exceptional item impairment of goodwill		**48.08p**				
Diluted earnings per ordinary share before goodwill amortisation and exceptional item	7	**38.77p**	35.60p			33.63p
Dividends per ordinary share	8	**22.50p**	20.50p			28.708p

The Accounting Policies and Definitions on pages 107 to 111, together with the Notes on pages 116 to 166 and 168 to 169 form part of these Accounts.

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Ø Statement of Total Recognised Gains and Losses

for the year ended 31 March 2005

	Notes	**2005** £m	2004 £m	2003 £m
(Loss)/profit for the financial year		**(308.1)**	537.9	482.6
Exchange movement on translation of overseas results and net assets	26	**(100.2)**	(537.6)	(387.0)
Translation differences on foreign currency hedging	26	**146.6**	475.2	357.6
Tax on translation differences on foreign currency hedging	26	**(46.4)**	46.1	(28.8)
Revaluation reserve arising on the purchase of the remaining 50% of the Brighton Power Station	26, 32	**5.8**		
Total recognised gains and losses for the financial year		**(302.3)**	521.6	424.4

Ø Reconciliation of Movements in Shareholders Funds

for the year ended 31 March 2005

	2005 £m	2004 £m	2003 £m
(Loss)/profit for the financial year	**(308.1)**	537.9	482.6
Dividends	**(412.6)**	(375.1)	(529.5)
(Loss)/profit retained	**(720.7)**	162.8	(46.9)
Exchange movement on translation of overseas results and net assets	**(100.2)**	(537.6)	(387.0)
Translation differences on foreign currency hedging	**146.6**	475.2	357.6
Tax on translation differences on foreign currency hedging	**(46.4)**	46.1	(28.8)
Revaluation reserve arising on the purchase of the remaining 50% of the Brighton Power Station	**5.8**		
Share capital issued	**21.9**	13.1	12.0
Consideration paid in respect of purchase of own shares held under trust	**(30.7)**	(28.9)	(36.2)
Credit in respect of employee share awards	**7.2**	4.9	10.0
Consideration received in respect of sale of own shares held under trust	**7.6**	0.4	6.4
Net movement in shareholders funds	**(708.9)**	136.0	(112.9)
Opening shareholders funds	**4,690.9**	4,554.9	4,667.8
Closing shareholders funds	**3,982.0**	4,690.9	4,554.9

The Accounting Policies and Definitions on pages 107 to 111, together with the Notes on pages 116 to 166 and 168 to 169 form part of these Accounts.

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Accounts 2004/05

Ø Group Cash Flow Statement

for the year ended 31 March 2005

	Notes	**2005 £m**	2004 £m	2003 £m
Cash inflow from operating activities	9	**1,259.7**	1,364.0	1,412.9
Dividends received from joint ventures and associates		**2.0**	0.5	0.9
Returns on investments and servicing of finance	10(a)	**(116.4)**	(210.0)	(297.0)
Taxation		**(99.2)**	(121.8)	(191.3)
Free cash flow		**1,046.1**	1,032.7	925.5
Capital expenditure and financial investment	10(b)	**(888.0)**	(831.2)	(675.1)
Cash flow before acquisitions and disposals		**158.1**	201.5	250.4
Acquisitions and disposals	10(c)	**(351.1)**	(31.3)	1,799.0
Equity dividends paid		**(386.1)**	(394.4)	(523.4)
Cash (outflow)/inflow before use of liquid resources and financing		**(579.1)**	(224.2)	1,526.0
Management of liquid resources	10(d), 13	**(185.9)**	(354.1)	(161.1)
Financing				
Issue of ordinary share capital	10(e)	**21.9**	13.1	12.0
Redemption of preferred stock of PacifiCorp	10(e)	**(4.1)**	(4.6)	(5.1)
Maturity of net investment hedging derivatives	10(e)	**140.0**		
Cancellation of cross-currency swaps	10(e)	**92.0**	76.1	
Repricing of cross-currency swaps	10(e)		403.0	
Net purchase of own shares held under trust	10(e)	**(23.1)**	(28.5)	(29.8)
Increase/(decrease) in debt	10(e), 13	**753.3**	464.3	(1,191.4)
		980.0	923.4	(1,214.3)
Increase in cash in year	13	**215.0**	345.1	150.6

Free cash flow represents cash flow from operating activities after adjusting for dividends received from joint ventures and associates, returns on investments and servicing of finance and taxation.

Ø Reconciliation of Net Cash Flow to Movement in Net Debt

for the year ended 31 March 2005

	Note	**2005 £m**	2004 £m	2003 £m
Increase in cash in year		**215.0**	345.1	150.6
Cash (inflow)/outflow from (increase)/decrease in debt		**(753.3)**	(464.3)	1,191.4
Cash outflow from movement in liquid resources		**185.9**	354.1	161.1
Change in net debt resulting from cash flows		**(352.4)**	234.9	1,503.1
Net debt disposed				100.0

Net debt acquired		**(116.1)**		
Foreign exchange movement		**62.4**	388.3	289.9
Other non-cash movements		**(16.4)**	(26.7)	(5.6)
Movement in net debt in year		**(422.5)**	596.5	1,887.4
Net debt at end of previous year		**(3,724.5)**	(4,321.0)	(6,208.4)
Net debt at end of year	13	**(4,147.0)**	(3,724.5)	(4,321.0)

The Accounting Policies and Definitions on pages 107 to 111, together with the Notes on pages 116 to 166 and 168 to 169 form part of these Accounts.

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Ø Group Balance Sheet

as at 31 March 2005

	Notes	2005 £m	2004 £m
Fixed assets			
Intangible assets	15	**845.4**	1,855.9
Tangible assets	16	**9,602.8**	8,756.6
Investments			
Investments in joint ventures:			
Share of gross assets		**85.0**	180.8
Share of gross liabilities		**(46.5)**	(157.3)
		38.5	23.5
Loans to joint ventures		**10.6**	38.8
		49.1	62.3
Investments in associates		**4.0**	2.7
Other investments		**120.3**	129.8
	17	**173.4**	194.8
		10,621.6	10,807.3
Current assets			
Stocks	18	**185.4**	185.5
Debtors			
Gross debtors		**1,856.6**	1,576.2
Less non-recourse financing		**(65.3)**	(109.5)
	19	**1,791.3**	1,466.7
Short-term bank and other deposits		**1,747.8**	1,347.3
		3,724.5	2,999.5
Creditors: amounts falling due within one year			
Loans and other borrowings	20	**(553.4)**	(410.7)
Other creditors	21	**(2,110.5)**	(1,658.7)
		(2,663.9)	(2,069.4)
Net current assets		**1,060.6**	930.1
Total assets less current liabilities		**11,682.2**	11,737.4
Creditors: amounts falling due after more than one year			
Loans and other borrowings (including convertible bonds)	20	**(5,341.4)**	(4,661.1)
Provisions for liabilities and charges			
Deferred tax	22	**(1,333.5)**	(1,242.2)
Other provisions	23	**(399.5)**	(504.5)
		(1,733.0)	(1,746.7)
Deferred income	24	**(570.1)**	(577.8)
Net assets	14	**4,037.7**	4,751.8
Called up share capital	25,26	**932.7**	929.8
Share premium	26	**2,294.7**	2,275.7
Revaluation reserve	26	**45.5**	41.6
Capital redemption reserve	26	**18.3**	18.3
Merger reserve	26	**406.4**	406.4
Profit and loss account	26	**284.4**	1,019.1
Equity shareholders funds	26	**3,982.0**	4,690.9
Minority interests (including non-equity)	27	**55.7**	60.9
Capital employed		**4,037.7**	4,751.8
Net asset value per ordinary share	14	**217.3p**	256.2p

Approved by the Board on 24 May 2005 and signed on its behalf by

Charles Miller Smith
Chairman

David Nish
Finance Director

The Accounting Policies and Definitions on pages 107 to 111, together with the Notes on pages 116 to 166 and 168 to 169 form part of these Accounts.

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Accounts 2004/05

Ø Notes to the Group Accounts

for the year ended 31 March 2005

1 Segmental profit and loss information

(a) Turnover by segment

		Total turnover			Inter-segment turnover			External turnover		
		2005	2004	2003	**2005**	2004	2003	**2005**	2004	2003
	Notes	**£m**	£m	£m	**£m**	£m	£m	**£m**	£m	£m
United Kingdom continuing operations										
UK Division Integrated Generation and Supply	(i)	**3,711.0**	2,804.0	2,180.8	**(25.9)**	(26.6)	(33.0)	**3,685.1**	2,777.4	2,147.8
Infrastructure Division Power Systems		**728.1**	704.1	667.3	**(348.0)**	(345.8)	(353.3)	**380.1**	358.3	314.0
United Kingdom total continuing operations								**4,065.2**	3,135.7	2,461.8
United States continuing operations										
PacifiCorp		**2,284.3**	2,321.1	2,502.2	**(2.8)**	(2.5)	(2.8)	**2,281.5**	2,318.6	2,499.4
PPM		**511.5**	352.9	293.6	**(9.4)**	(10.1)	(7.7)	**502.1**	342.8	285.9
United States total continuing operations								**2,783.6**	2,661.4	2,785.3
Total continuing operations								**6,848.8**	5,797.1	5,247.1
United Kingdom discontinued operations										
Southern Water				26.7						26.7
United Kingdom total discontinued operations										26.7
Total	(ii)							**6,848.8**	5,797.1	5,273.8

(b) Operating profit by segment

Note	**Before goodwill amortisation and exceptional item 2005**	**Goodwill amortisation 2005 £m**	**Exceptional item impairment of goodwill (Note 4) 2005 £m**	**2005 £m**	Before goodwill amortisation 2004 £m	Goodwill amortisation 2004 £m	2004 £m	Before goodwill amortisation 2003 £m	Goodwill amortisation 2003 £m	2003 £m

		£m									
United Kingdom continuing operations											
UK Division Integrated Generation and Supply	(i)	**180.5**	**(4.9)**		**175.6**	101.0	(4.9)	96.1	77.9	(4.9)	73.0
Infrastructure Division Power Systems		**416.3**			**416.3**	393.6		393.6	367.8		367.8
United Kingdom total continuing operations		**596.8**	**(4.9)**		**591.9**	494.6	(4.9)	489.7	445.7	(4.9)	440.8
United States continuing operations											
PacifiCorp		**541.7**	**(112.1)**	**(927.0)**	**(497.4)**	619.3	(122.5)	496.8	596.7	(133.9)	462.8
PPM		**58.6**	**(0.5)**		**58.1**	36.7	(0.6)	36.1	28.5	(0.2)	28.3
United States total continuing operations		**600.3**	**(112.6)**	**(927.0)**	**(439.3)**	656.0	(123.1)	532.9	625.2	(134.1)	491.1
Total continuing operations		**1,197.1**	**(117.5)**	**(927.0)**	**152.6**	1,150.6	(128.0)	1,022.6	1,070.9	(139.0)	931.9
United Kingdom discontinued operations											
Southern Water									14.0		14.0
United Kingdom total discontinued operations									14.0		14.0
Total		**1,197.1**	**(117.5)**	**(927.0)**	**152.6**	1,150.6	(128.0)	1,022.6	1,084.9	(139.0)	945.9

(c) Depreciation by segment

	Note	**Depreciation 2005 £m**	Depreciation 2004 £m	Depreciation 2003 £m
United Kingdom continuing operations				
UK Division Integrated Generation and Supply		**121.8**	88.5	87.3
Infrastructure Division Power Systems		**111.4**	109.1	112.4
United Kingdom total continuing operations		**233.2**	197.6	199.7
United States continuing operations				
PacifiCorp		**211.7**	230.1	233.9
PPM		**13.3**	11.0	8.0
United States total continuing operations		**225.0**	241.1	241.9
Total continuing operations		**458.2**	438.7	441.6
United Kingdom discontinued operations				
Southern Water				5.6
United Kingdom total discontinued operations				5.6
	16	**458.2**	438.7	447.2

(i) UK Division Integrated Generation and Supply completed the acquisition of the Damhead Creek CCGT power plant and associated contracts on 1 June 2004 and completed the purchase of the remaining 50% of the Brighton Power Station CCGT power plant and associated contracts on 28 September 2004. The post acquisition results of the acquired businesses amounted to turnover of £162.2 million and operating profit of £53.6 million. Further details of these acquisitions are contained within Note 32.

(ii) In the segmental analysis turnover is shown by geographical origin. Turnover analysed by geographical destination is not materially different.

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2 Operating profit

(a) Operating profit is stated after charging/(crediting):	Note	**2005 £m**	2004 £m	2003 £m
Depreciation of tangible fixed assets		**458.2**	438.7	447.2
Amortisation of goodwill		**117.5**	128.0	139.0
Exceptional item impairment of goodwill	4	**927.0**		
Amortisation of other intangible fixed assets		**24.4**		
Release of grants and customer contributions		**(19.2)**	(19.5)	(18.6)
Research and development		**0.2**	0.2	0.7
Hire of plant and equipment operating leases		**0.1**	0.1	0.1
Hire of other assets operating leases		**14.6**	16.2	14.6
Operating lease rentals receivable		**(2.1)**	(2.0)	(2.2)

Operating profit for the years ended 31 March 2005, 31 March 2004 and 31 March 2003 is also stated after (crediting)/charging £(2.9) million, £(2.9) million and £27.8 million respectively in relation to finance leases in the US, which are financed by non-recourse borrowings and qualify for linked presentation under FRS 5. Net earnings comprise gross (earnings)/loss, after provision against the carrying value of the group s residual interests, of £(33.3) million, £(32.4) million and £3.2 million less finance costs of £30.4 million, £29.5 million and £24.6 million respectively.

(b) Auditors remuneration	**2005 £m**	2004 £m	2003 £m
Audit services			
statutory audit	**1.7**	1.5	1.5
audit-related regulatory reporting	**0.7**	0.4	0.6
Further assurance services	**2.5**	0.7	0.7
Tax services			
compliance services	**1.0**	1.6	1.6
advisory services	**0.4**	0.8	3.2
Other services			0.3
Total UK and US audit and non-audit fees paid to auditors	**6.3**	5.0	7.9

The Audit Committee and the firm of external auditors have safeguards to avoid the possibility that the auditors objectivity and independence could be compromised. These safeguards include the adoption by the Committee of a policy regarding pre-approval of audit and permitted non-statutory audit services provided by the external auditors and a policy on the hiring of external audit staff.

Where it is deemed that the work to be undertaken is of a nature that is generally considered reasonable to be completed by the auditor of the group for sound commercial and practical reasons, including confidentiality, the conduct of such work will be permissible provided that it has been pre-approved by the Audit Committee. Examples of pre-approved services include the completion of regulatory audits, provision of taxation and regulatory advice, reporting in relation to the Securities and Exchange Commission and the UK Listing Authority requirements and the completion of certain financial due diligence work. All these services are also subject to a pre-defined fee limit. Any work performed in excess of this limit must be approved by the Finance Director and the Chairman of the Audit Committee.

Fees and expenses invoiced by the auditors, excluding statutory audit fees, include £2.5 million (2004 £1.5 million, 2003 £2.3 million) payable in the UK.

For the year ended 31 March 2005, £3.9 million of fees, excluding statutory audit, were charged to operating profit and £0.7 million were included within the cost of acquisitions. For the years ended 31 March 2004 and 31 March 2003, all fees, excluding statutory audit, were charged to operating profit.

Further assurance services principally represents fees associated with due dilligence work and advice regarding the implementation of s404 of the Sarbanes-Oxley Act of 2002 and the implementation of International Financial Reporting Standards (IFRS).

Fees for Other services for the year ended 31 March 2003 included an amount of £0.3 million which was paid to PricewaterhouseCoopers Consulting in the period prior to its disposal by PricewaterhouseCoopers on 2 October 2003.

3 Employee information

		2005	2004	2003
(a) Employee costs	Note	**£m**	£m	£m
Wages and salaries		**579.0**	525.6	553.1
Social security costs		**41.1**	35.7	36.7
Pension and other costs	(i)	**101.6**	98.1	68.0
Total employee costs		**721.7**	659.4	657.8
Less: charged as capital expenditure		**(151.8)**	(161.6)	(155.2)
Charged to the profit and loss account		**569.9**	497.8	502.6

(i) Pension costs above comprise pension costs, company contributions to the PacifiCorp 401(k) plan and costs of other post-retirement and other post-employment benefits. The cost of the group s pension arrangements for the year ended 31 March 2005 was £74.2 million (2004 £66.7 million, 2003 £41.8 million).

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Accounts 2004/05

Ø Notes to the Group Accounts continued

for the year ended 31 March 2005

3 Employee information continued

(b) Employee numbers

The year end and average numbers of employees (full-time and part-time) employed by the group, including executive directors, were:

	Note	At 31 March **2005**	2004	2003	Annual average **2005**	2004	2003
United Kingdom continuing operations							
UK Division Integrated Generation and Supply		**5,667**	4,793	4,319	**5,227**	4,523	4,362
Infrastructure Division Power Systems		**3,541**	3,324	3,215	**3,454**	3,256	3,238
United Kingdom total continuing operations		**9,208**	8,117	7,534	**8,681**	7,779	7,600
United States continuing operations							
PacifiCorp		**6,656**	6,510	6,130	**6,620**	6,339	6,175
PPM		**278**	194	161	**240**	180	128
United States total continuing operations		**6,934**	6,704	6,291	**6,860**	6,519	6,303
Total continuing operations		**16,142**	14,821	13,825	**15,541**	14,298	13,903
United Kingdom discontinued operations							
Southern Water							2,024
United Kingdom total discontinued operations	(i)						2,024
Total		**16,142**	14,821	13,825	**15,541**	14,298	15,927

The year end and average numbers of full-time equivalent staff employed by the group, including executive directors, were:

	Note	At 31 March **2005**	2004	2003	Annual average **2005**	2004	2003
United Kingdom							
continuing operations		8,739	7,736	7,163	8,378	7,413	7,240
discontinued operations	(i)						1,982
United States		**6,883**	6,663	6,265	**6,812**	6,476	6,268
Total		**15,622**	14,399	13,428	**15,190**	13,889	15,490

(i) The annual average for the year ended 31 March 2003 for Southern Water was calculated for the period prior to disposal on 23 April 2002.

(c) Directors remuneration

Details, for each director, of remuneration, pension entitlements and interests in share options are set out on pages 101 to 105. This information forms part of the Accounts.

4 Exceptional item

In November 2004, the Board began a strategic review of PacifiCorp as a result of its performance and the significant investment it required in the immediate future. In May 2005, the Board concluded that in light of the prospects for PacifiCorp, the scale and timing of the capital investment required and the likely profile of returns, shareholders interests were best served by a sale of PacifiCorp and the return of capital to shareholders. As a consequence, the group has undertaken a review of the carrying value of the goodwill allocated to the PacifiCorp reporting segment as at 31 March 2005. The estimated recoverable value has been based on net realisable value, with reference to the price of comparable businesses, recent market transactions and the estimated proceeds from disposal. This has resulted in an exceptional charge, in the year ended 31 March 2005 for the impairment of goodwill of £927 million which is disclosed separately within operating profit as an exceptional item.

5 Net interest and similar charges

		2005	2004	2003
Analysis of net interest and similar charges	Notes	**£m**	£m	£m
Interest on bank loans and overdrafts		**18.8**	13.4	18.6
Interest on other borrowings		**310.6**	310.9	331.0
Finance leases		**1.8**	1.9	2.1
Total interest payable		**331.2**	326.2	351.7
Interest receivable		**(148.2)**	(97.7)	(107.1)
Capitalised interest	(i)	**(11.6)**	(10.5)	(17.3)
Net interest charge		**171.4**	218.0	227.3
Unwinding of discount on provisions		**18.6**	20.1	26.5
Foreign exchange (gain)/loss		**(2.1)**		0.5
Net interest and similar charges		**187.9**	238.1	254.3
Interest cover (times)	(ii)	**6.3**	4.9	4.3

(i) The tax relief on the capitalised interest was £0.5 million (2004 £0.1 million, 2003 £4.4 million) and gives rise to timing differences on which deferred tax is recognised.

(ii) Interest cover is calculated by dividing profit on ordinary activities before interest (before goodwill amortisation and exceptional item) by the sum of the net interest charge and the unwinding of discount on provisions.

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6 Tax on (loss)/profit on ordinary activities

	2005	2004	2003
	£m	£m	£m
Current tax:			
UK Corporation tax	**184.5**	145.9	124.4
Adjustments in respect of prior years	**(40.7)**	25.8	(44.9)
Total UK Corporation tax for year	**143.8**	171.7	79.5
Foreign tax	**7.7**	36.2	78.9
Adjustments in respect of prior years	**5.9**	(33.9)	
Total Foreign tax for year	**13.6**	2.3	78.9
Total current tax for year	**157.4**	174.0	158.4
Deferred tax:			
Origination and reversal of timing differences	**119.1**	77.3	50.6
Adjustments in respect of prior years	**(2.4)**	(2.9)	
Total deferred tax for year	**116.7**	74.4	50.6
Total tax on (loss)/profit on ordinary activities	**274.1**	248.4	209.0
Effective rate of tax before goodwill amortisation and exceptional item	**27.0%**	27.0%	25.0%

The current tax charge on (loss)/profit on ordinary activities for the year varied from the standard rate of UK Corporation tax as follows:

	2005	2004	2003
	£m	£m	£m
Corporation tax at 30%	**(8.8)**	237.6	209.0
Effect of tax rate applied to overseas earnings	**26.0**	(4.1)	(0.7)
Goodwill amortisation	**35.2**	38.4	41.7
Adjustments in respect of prior years	**(37.2)**	(11.0)	(44.9)
Permanent difference on exceptional item	**278.1**		
Other permanent differences	**(19.2)**	(12.5)	3.9
Tax charge (current and deferred)	**274.1**	248.4	209.0
Origination and reversal of timing differences deferred tax charge	**(116.7)**	(74.4)	(50.6)
Current tax charge for year	**157.4**	174.0	158.4

7 (Loss)/earnings per ordinary share

(a) (Loss)/earnings per ordinary share have been calculated for all years by dividing the (loss)/profit for the financial year by the weighted average number of ordinary shares in issue during the financial year, based on the following information:

	2005	2004	2003
Basic (loss)/earnings per share			
(Loss)/profit for the financial year (£ million)	**(308.1)**	537.9	482.6
Weighted average share capital (number of shares, million)	**1,830.8**	1,829.5	1,843.9
Diluted (loss)/earnings per share			
(Loss)/profit for the financial year (£ million)	**(308.1)**	545.0	482.6
Weighted average share capital (number of shares, million)	**1,830.8**	1,890.2	1,848.4

The difference between the (loss)/profit for the financial year for the purposes of the basic and the diluted earnings per share calculations is analysed as follows:

	2005	2004	2003
	£m	£m	£m
Basic (loss)/earnings per share (loss)/profit for the financial year	**(308.1)**	537.9	482.6

Interest on convertible bonds		7.1	
Diluted (loss)/earnings per share (loss)/profit for the financial year	**(308.1)**	545.0	482.6

The difference between the weighted average share capital for the purposes of the basic and the diluted (loss)/earnings per share calculations is analysed as follows:

	2005	2004	2003
Number of shares (million)			
Basic (loss)/earnings per share weighted average share capital	**1,830.8**	1,829.5	1,843.9
Outstanding share options and shares held in trust for the group s employee share schemes		4.9	4.5
Convertible bonds		55.8	
Diluted (loss)/earnings per share weighted average share capital	**1,830.8**	1,890.2	1,848.4

There is no dilution of the basic loss per share for the year ended 31 March 2005 as the potentially dilutive shares would decrease the loss per share.

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7 (Loss)/earnings per ordinary share continued

(b) The calculation of (loss)/earnings per ordinary share, on a basis which excludes goodwill amortisation and exceptional item, is based on the following information:

	Continuing operations and Total 2005	Continuing operations and Total 2004	Continuing operations 2003	Discontinued operations 2003	Total 2003
Adjusted basic earnings per share	**£m**	£m	£m	£m	£m
(Loss)/profit for the financial year	**(308.1)**	537.9	475.0	7.6	482.6
Adjusting items goodwill amortization	**117.5**	128.0	139.0		139.0
exceptional item impairment of goodwill	**927.0**				
Adjusted basic earnings	**736.4**	665.9	614.0	7.6	621.6

	Continuing operations and Total 2005	Continuing operations and Total 2004	Continuing operations 2003	Discontinued operations 2003	Total 2003
Adjusted diluted earnings per share	**£m**	£m	£m	£m	£m
(Loss)/profit for the financial year	**(308.1)**	537.9	475.0	7.6	482.6
Interest on convertible bonds	**11.0**	7.1			
Adjusting items goodwill amortization	**117.5**	128.0	139.0		139.0
exceptional item impairment of goodwill	**927.0**				
Adjusted diluted earnings	**747.4**	673.0	614.0	7.6	621.6

The difference between the weighted average share capital for the purposes of the adjusted basic and the adjusted diluted earnings per share calculations is analysed as follows:

	2005	2004	2003
Number of shares (million)			
Adjusted basic earnings per share weighted average share capital	**1,830.8**	1,829.5	1,843.9
Outstanding share options and shares held in trust for the group s employee share schemes	**6.2**	4.9	4.5
Convertible bonds	**91.0**	55.8	
Adjusted diluted earnings per share weighted average share capital	**1,928.0**	1,890.2	1,848.4

ScottishPower assesses the performance of the group by adjusting earnings per share, calculated in accordance with FRS 14, to exclude items it considers to be non-recurring or non-operational in nature and believes that the exclusion of such items provides a better comparison of business performance. Consequently, an adjusted earnings per share figure is presented for all years.

Where potentially dilutive shares would dilute the adjusted basic earnings per share, such dilutive shares have been used in the calculation of the adjusted diluted earnings per share as this is considered to provide a better comparison of business performance. If such potentially dilutive shares were not used in the calculation of the adjusted diluted earnings per share, the adjusted dilutive earnings per share would be the same as the adjusted basic earnings per share.

The group s net interest and similar charges have been allocated between continuing and discontinued operations on the basis of external and internal borrowings of the respective operations. The group s tax charge has been allocated between continuing and discontinued operations based on the profit before tax of the respective operations.

8 Dividends

	2005 pence per ordinary share	2004 pence per ordinary share	2003 pence per ordinary share	**2005 £m**	2004 £m	2003 £m
First interim dividend paid	**4.95**	4.75	7.177	**91.1**	87.5	132.5
Second interim dividend paid	**4.95**	4.75	7.177	**91.0**	87.4	132.7
Third interim dividend paid	**4.95**	4.75	7.177	**91.1**	87.3	132.1
Final dividend	**7.65**	6.25	7.177	**139.4**	112.9	132.2
Total dividends	**22.50**	20.50	28.708	**412.6**	375.1	529.5

9 Reconciliation of operating profit to net cash inflow from operating activities

	2005 £m	2004 £m	2003 £m
Operating profit	**152.6**	1,022.6	945.9
Depreciation, amortisation and impairment	**1,527.1**	566.7	586.2
(Profit)/loss on sale of tangible fixed assets	**(0.7)**	(0.4)	2.7
Amortisation of share scheme costs	**7.2**	4.9	10.0
Release of deferred income	**(19.2)**	(19.5)	(18.6)
Movements in provisions for liabilities and charges	**(202.1)**	(87.6)	(77.5)
Increase in stocks	**(1.9)**	(51.0)	(1.9)
Increase in debtors	**(394.6)**	(38.7)	(169.4)
Increase/(decrease) in creditors	**191.3**	(33.0)	135.5
Net cash inflow from operating activities	**1,259.7**	1,364.0	1,412.9

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10 Analysis of cash flows

	Note	2005 £m	2004 £m	2003 £m
(a) Returns on investments and servicing of finance				
Interest received		**152.5**	87.6	112.0
Interest paid		**(264.6)**	(293.0)	(404.2)
Dividends paid to minority interests		**(4.3)**	(4.6)	(4.8)
Net cash outflow for returns on investments and servicing of finance		**(116.4)**	(210.0)	(297.0)
(b) Capital expenditure and financial investment				
Purchase of tangible fixed assets		**(939.8)**	(892.2)	(735.9)
Deferred income received		**51.3**	48.2	69.5
Deferred income repaid		**(37.3)**		
Sale of tangible fixed assets		**23.0**	12.2	10.4
Sale/(purchase) of fixed asset investments		**14.8**	0.6	(19.1)
Net cash outflow for capital expenditure and financial investment		**(888.0)**	(831.2)	(675.1)
(c) Acquisitions and disposals				
Purchase of Maple Ridge and Colorado Green joint ventures	12	**(18.3)**	(24.6)	
Purchase of businesses and subsidiary undertakings	12	**(325.4)**		(101.3)
Sale of businesses and subsidiary undertakings	12	**(7.4)**	(6.7)	1,900.3
Net cash (outflow)/inflow from acquisitions and disposals		**(351.1)**	(31.3)	1,799.0
(d) Management of liquid resources*				
Cash outflow in relation to short-term deposits and other short-term investments		**(185.9)**	(354.1)	(161.1)
Net cash outflow for management of liquid resources		**(185.9)**	(354.1)	(161.1)
(e) Financing				
Issue of ordinary share capital		**21.9**	13.1	12.0
Redemption of preferred stock of PacifiCorp		**(4.1)**	(4.6)	(5.1)
Maturity of net investment hedging derivatives		**140.0**		
Cancellation of cross-currency swaps		**92.0**	76.1	
Repricing of cross-currency swaps			403.0	
Net purchase of own shares held under trust		**(23.1)**	(28.5)	(29.8)
		226.7	459.1	(22.9)
Debt due within one year:				
net (repayment)/drawdown of uncommitted facilities		**(108.0)**	98.7	(203.6)
repayment of committed bank loan				(100.0)
net commercial paper issued/(redeemed)		**184.0**	64.9	(288.9)
medium-term notes/private placements		**(69.6)**	(29.3)	(86.4)
redemption of loan notes			(2.5)	(2.2)
European Investment Bank loans				(129.2)
mortgages		**(86.9)**	(83.0)	(5.9)
5.875% euro-US dollar bond 2003				(183.5)
other		**3.8**	(6.1)	18.3
Debt due after one year:				
medium-term notes/private placements			2.1	(127.3)
mortgages		**164.9**	216.0	(83.0)
convertible bonds			409.9	
4.910% US dollar bond 2010		**284.5**		
5.375% US dollar bond 2015		**319.0**		
5.810% US dollar bond 2025		**180.1**		
secured pollution control revenue bonds			68.3	
unsecured pollution control revenue bonds			(68.4)	2.1
preferred securities			(205.1)	0.3
repayment of bank loan acquired		**(116.1)**		

other	**(1.9)**	(1.2)	(2.1)
Finance leases:			
finance leases	**(0.5)**		
Increase/(decrease) in debt	**753.3**	464.3	(1,191.4)
Net cash inflow/(outflow) from financing	**980.0**	923.4	(1,214.3)

* Liquid resources include term deposits of less than one year, commercial paper and other short-term investments.

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11 Effect of acquisitions and disposals on cash flows

	Acquisitions 2005	Acquisition 2003	Disposal 2003
	£m	£m	£m
Cash inflow from operating activities	**34.2**	1.0	16.0
Returns on investments and servicing of finance	**(15.5)**		(6.6)
Taxation	**(0.2)**		
Capital expenditure and financial investment	**(4.4)**	(1.4)	(9.2)
Financing			4.5
Increase/(decrease) in cash	**14.1**	(0.4)	4.7

The analysis of cash flows of the acquisitions for the year ended 31 March 2005 relate to the post-acquisition cash flows of Damhead Creek, the remaining 50% of Brighton Power Station and Atlantic Renewable Energy Corporation.

The analysis of cash flows of the acquisition for the year ended 31 March 2003 related to the post-acquisition cash flows of the Katy gas storage facility. The effect of the disposal on cash flows for the year ended 31 March 2003 related to the disposal of Southern Water.

12 Analysis of cash flows in respect of acquisitions and disposals

	Acquisitions 2005	**Disposals 2005**	Acquisition 2004	Disposals 2004	Acquisition 2003	Disposals 2003
	£m	**£m**	£m	£m	£m	£m
Cash consideration for joint ventures including expenses	**(18.3)**		(24.6)			
Cash consideration for businesses and subsidiary undertakings including expenses	**(352.2)**				(101.3)	1,139.4
Cash settlement of inter-company loan						756.4
Cash acquired/bank overdraft disposed	**26.8**					6.2
Deferred consideration in respect of prior year disposals						10.5
Expenses and other costs paid in respect of prior year disposals		**(7.4)**		(6.7)		(12.2)
	(343.7)	**(7.4)**	(24.6)	(6.7)	(101.3)	1,900.3

For the year ended 31 March 2005, the cash flows in respect of acquisitions of businesses and subsidiary undertakings represents the purchase of Damhead Creek, the remaining 50% of Brighton Power Station and Atlantic Renewable Energy Corporation. The cash flows in respect of acquisitions of joint ventures principally represents PPM s investment in the Maple Ridge joint venture. The cash flows in respect of disposals represent expenses and other costs related to prior year disposals.

For the year ended 31 March 2004, the cash flows in respect of the acquisition of joint ventures represented PPM s investment in the Colorado Green joint venture. The cash flows in respect of disposals principally represented expenses and other costs related to the disposal of and withdrawal from Appliance Retailing.

For the year ended 31 March 2003, the cash flows in respect of the acquisition represented the purchase of the Katy gas storage facility. The cash flows in respect of disposals principally represented the proceeds from the sale of Southern Water.

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13 Analysis of net debt

2003/04	At 1 April 2003 £m	Cash flow £m	Exchange £m	Other non-cash changes £m	At 31 March 2004 £m
Cash at bank	430.1	346.6	(17.8)		758.9
Overdrafts	(21.1)	(1.5)	2.5		(20.1)
		345.1			
Debt due after 1 year	(4,759.6)	(421.6)	364.0	171.1	(4,646.1)
Debt due within 1 year	(187.4)	(42.7)	37.3	(197.8)	(390.6)
Finance leases	(17.5)		2.5		(15.0)
		(464.3)			
Other deposits	234.5	354.1	(0.2)		588.4
Total	(4,321.0)	234.9	388.3	(26.7)	(3,724.5)

Other non-cash changes to net debt represents the movement in debt of £197.8 million due after one year to due within one year, the share of debt in joint arrangements of £6.4 million, amortisation of finance costs of £6.1 million and finance costs of £14.2 million representing the effects of the RPI on bonds carrying an RPI coupon.

2004/05	At 1 April 2004 £m	Cash flow £m	Acquisitions (excluding cash & overdrafts) £m	Exchange £m	Other non-cash changes £m	**At 31 March 2005 £m**
Cash at bank	758.9	216.4		(1.8)		**973.5**
Overdrafts	(20.1)	(1.4)		1.0		**(20.5)**
		215.0				
Debt due after 1 year	(4,646.1)	(830.5)	(116.1)	54.3	211.0	**(5,327.4)**
Debt due within 1 year	(390.6)	76.7		8.4	(227.4)	**(532.9)**
Finance leases	(15.0)	0.5		0.5		**(14.0)**
		(753.3)				
Other deposits	588.4	185.9				**774.3**
Total	(3,724.5)	(352.4)	(116.1)	62.4	(16.4)	**(4,147.0)**

Other non-cash changes to net debt represents the movement in debt of £227.9 million due after one year to due within one year, amortisation of finance costs of £7.1 million and finance costs of £9.3 million representing the effects of the RPI on bonds carrying an RPI coupon.

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14 Segmental balance sheet information

(a) Net assets by segment	Notes	2005 £m	2004 £m
United Kingdom			
UK Division Integrated Generation and Supply	(i)	**1,734.3**	1,022.5
Infrastructure Division Power Systems		**2,479.8**	2,337.4
United Kingdom total		**4,214.1**	3,359.9
United States			
PacifiCorp		**5,071.3**	5,935.8
PPM		**469.3**	439.0
United States total		**5,540.6**	6,374.8
Total		**9,754.7**	9,734.7
Unallocated net liabilities			
Net debt		**(4,147.0)**	(3,724.5)
Deferred tax		**(1,333.5)**	(1,242.2)
Corporate tax		**(338.9)**	(237.7)
Proposed dividend		**(139.4)**	(112.9)
Fixed asset investments		**173.4**	194.8
Other	(ii)	**68.4**	139.6
Total unallocated net liabilities		**(5,717.0)**	(4,982.9)
Total		**4,037.7**	4,751.8

Net asset value per ordinary share has been calculated based on net assets (after adjusting for minority interests) and the number of shares in issue (after adjusting for the effect of shares held in trust) at the end of the respective financial years:

	2005	2004
Net assets (as adjusted) (£ million)	**3,982.0**	4,690.9
Number of ordinary shares in issue at year end (as adjusted) (number of shares, million)	**1,832.3**	1,830.6

(b) Capital expenditure by segment	Note	2005 £m	2004 £m
United Kingdom			
UK Division Integrated Generation and Supply	(iii)	**155.0**	93.4
Infrastructure Division Power Systems	(iii)	**291.8**	287.2
United Kingdom total		**446.8**	380.6
United States			
PacifiCorp	(iii)	**506.1**	464.6
PPM		**59.8**	103.8
United States total		**565.9**	568.4
Total		**1,012.7**	949.0

(c) Total assets by segment	Notes	2005	2004

		£m	£m
United Kingdom			
UK Division Integrated Generation and Supply	(i)	**2,556.5**	1,742.6
Infrastructure Division Power Systems		**3,165.8**	2,976.0
United Kingdom total		**5,722.3**	4,718.6
United States			
PacifiCorp		**5,856.3**	6,718.7
PPM		**667.0**	556.2
United States total		**6,523.3**	7,274.9
Total		**12,245.6**	11,993.5
Unallocated total assets	(iv)	**2,100.5**	1,813.3
Total		**14,346.1**	13,806.8

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14 Segmental balance sheet information continued

(i) UK Division Integrated Generation and Supply completed the acquisition of the Damhead Creek CCGT power plant and associated contracts on 1 June 2004 and completed the purchase of the remaining 50% of the Brighton Power Station CCGT power plant and associated contracts on 28 September 2004. Further details of these acquisitions are contained within Note 32.

(ii) Other unallocated net liabilities principally includes interest and amounts relating to gains arising on retranslation of forward contracts and cross-currency swaps used to hedge overseas net investments.

(iii) Capital expenditure by business segment is stated gross of capital grants and customer contributions and excludes acquisitions. Capital expenditure net of contributions amounted to £961.4 million (2004 £900.8 million). Capital grants and customer contributions receivable during the year of £51.3 million (2004 £48.2 million) comprised UK Division Integrated Generation and Supply £0.5 million (2004 £0.1 million), Infrastructure Division Power Systems £25.1 million (2004 £27.6 million) and PacifiCorp £25.7 million (2004 £20.5 million).

(iv) Unallocated total assets includes investments, interest receivable, bank deposits and amounts relating to gains arising on retranslation of forward contracts and cross-currency swaps used to hedge overseas net investments.

15 Intangible fixed assets

Year ended 31 March 2004	Goodwill £m	Other £m	Total £m
Cost:			
At 1 April 2003	2,704.2		2,704.2
Exchange	(364.5)		(364.5)
At 31 March 2004	2,339.7		2,339.7
Amortisation:			
At 1 April 2003	423.6		423.6
Amortisation for the year	128.0		128.0
Exchange	(67.8)		(67.8)
At 31 March 2004	483.8		483.8
Net book value:			
At 31 March 2004	1,855.9		1,855.9
At 31 March 2003	2,280.6		2,280.6

Year ended 31 March 2005	Notes	Goodwill £m	Other £m	Total £m
Cost:				
At 1 April 2004		2,339.7		2,339.7
Acquisitions	32		104.6	104.6
Exchange		(61.7)		(61.7)
At 31 March 2005		**2,278.0**	**104.6**	**2,382.6**
Amortisation:				
At 1 April 2004		483.8		483.8
Amortisation for the year		117.5	24.4	141.9
Impairment	4	927.0		927.0
Exchange		(15.5)		(15.5)
At 31 March 2005		**1,512.8**	**24.4**	**1,537.2**
Net book value:				
At 31 March 2005		**765.2**	**80.2**	**845.4**
At 31 March 2004		1,855.9		1,855.9

Goodwill capitalised is being amortised over its estimated useful economic life of 20 years.

Other intangible fixed assets represent in-the-money gas contracts acquired as part of the Damhead Creek and Brighton Power Station acquisitions and are being amortised over the life of the respective contracts.

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16 Tangible fixed assets

Year ended 31 March 2004	Note	Land and buildings £m	Plant and machinery £m	Vehicles and equipment £m	Total £m
Cost or valuation:					
At 1 April 2003		632.7	9,750.8	1,166.5	11,550.0
Reclassification		(21.3)	2.8	18.5	
Additions	(i)	16.0	677.2	255.8	949.0
Disposals		(7.2)	(15.6)	(30.1)	(52.9)
Exchange		(24.8)	(772.5)	(89.7)	(887.0)
At 31 March 2004		595.4	9,642.7	1,321.0	11,559.1
Depreciation:					
At 1 April 2003		177.3	1,819.4	524.6	2,521.3
Reclassification		(14.7)	(1.0)	15.7	
Charge for the year		20.1	245.6	173.0	438.7
Disposals		(1.0)	(15.6)	(24.5)	(41.1)
Exchange			(82.1)	(34.3)	(116.4)
At 31 March 2004		181.7	1,966.3	654.5	2,802.5
Net book value:					
At 31 March 2004		413.7	7,676.4	666.5	8,756.6
At 31 March 2003		455.4	7,931.4	641.9	9,028.7

Year ended 31 March 2005	Note	Land and buildings £m	Plant and machinery £m	Vehicles and equipment £m	Total £m
Cost or valuation:					
At 1 April 2004		595.4	9,642.7	1,321.0	11,559.1
Additions		23.8	872.2	116.7	1,012.7
Acquisitions	32	13.1	439.1		452.2
Disposals		(3.0)	(92.7)	(62.4)	(158.1)
Exchange		(4.5)	(139.8)	(21.3)	(165.6)
At 31 March 2005		**624.8**	**10,721.5**	**1,354.0**	**12,700.3**
Depreciation:					
At 1 April 2004		181.7	1,966.3	654.5	2,802.5
Charge for the year		18.3	299.9	140.0	458.2
Disposals		(2.0)	(79.8)	(54.0)	(135.8)
Exchange		(0.6)	(18.6)	(8.2)	(27.4)
At 31 March 2005		**197.4**	**2,167.8**	**732.3**	**3,097.5**
Net book value:					
At 31 March 2005		**427.4**	**8,553.7**	**621.7**	**9,602.8**

At 31 March 2004	413.7	7,676.4	666.5	8,756.6

	2005	2004
Historical cost analysis	**£m**	£m
Cost	**12,646.3**	11,505.1
Depreciation based on cost	**(3,083.2)**	(2,790.1)
Net book value based on cost	**9,563.1**	8,715.0

		2005	2004
Included in the cost or valuation of tangible fixed assets above are:	Notes	**£m**	£m
Assets in the course of construction		**779.7**	637.8
Other assets not subject to depreciation	(iii)	**135.0**	118.4
Capitalised interest	(iv)	**56.8**	46.2

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16 Tangible fixed assets continued

(i) Additions in the prior year of £949.0 million included £24.9 million relating to an increase in the provision for mine reclamation costs.

(ii) The Manweb distribution operational assets were revalued by the directors on 30 September 1997 on a market value basis. The valuation of the Manweb distribution assets has not been and will not be updated, as permitted under the transitional provisions of FRS 15 Tangible fixed assets . The net book value of tangible fixed assets included at valuation at 31 March 2005 was £545.7 million (2004 £563.9 million).

(iii) Other assets not subject to depreciation are land. Land and buildings held by the group are predominantly freehold.

(iv) Interest on the funding attributable to major capital projects was capitalised during the year at a rate of 6% (2004 nil) in the UK and 6% (2004 6%) in the US.

(v) The historical cost of fully depreciated tangible fixed assets still in use was £553.1 million (2004 £375.6 million).

(vi) Capitalised computer software costs developed for internal use include employee, interest and other external direct costs of materials and services which are directly attributable to the development of computer software. Cumulative computer software costs capitalised are £601.3 million (2004 £560.8 million). The depreciation charge was £69.2 million (2004 £61.2 million, 2003 £79.6 million).

(vii) The net book value of land and buildings under finance leases at 31 March 2005 was £14.4 million (2004 £15.0 million). The charge for depreciation against these assets during the year was £0.6 million (2004 £0.7 million, 2003 £0.1 million). This principally represents office buildings.

(viii) The cost or valuation of assets held for use in operating leases at 31 March 2005 was £8.7 million (2004 £8.7 million). The accumulated depreciation charged against the assets at 31 March 2005 was £0.8 million (2004 £0.6 million).

17 Fixed asset investments

		Joint ventures		Associated undertakings		
		Shares	Loans	Shares	Other investments	Total
	Note	£m	£m	£m	£m	£m
Cost or valuation:						
At 31 March 2003		0.1	40.2	2.8	150.2	193.3
Additions		24.6	1.1		2.2	27.9
Share of retained profit		0.5		0.2		0.7
Disposals and other			(2.5)	(0.3)	(1.6)	(4.4)
Exchange		(1.7)			(21.0)	(22.7)
At 31 March 2004		23.5	38.8	2.7	129.8	194.8
Additions		18.3	1.5		4.9	24.7
Share of retained (loss)/profit		(0.4)	(1.8)	2.2		
Disposals and other		(2.3)	(8.8)	(0.9)	(11.2)	(23.2)
Transfer of joint venture to subsidiary	32		(19.1)			(19.1)
Exchange		(0.6)			(3.2)	(3.8)
At 31 March 2005		**38.5**	**10.6**	**4.0**	**120.3**	**173.4**

The principal subsidiary undertakings, joint ventures and associated undertakings are listed on page 169.

Details of listed investments, included above, are given below:

	£m
Balance Sheet value at 31 March 2005	48.8
Market value at 31 March 2005	46.9

18 Stocks

	2005	2004
	£m	£m
Raw materials and consumables	**110.8**	91.7
Fuel stocks	**71.1**	88.2
Work in progress	**3.5**	5.6
	185.4	185.5

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19 Debtors

		Notes	2005 £m	2004 £m
(a) Amounts falling due within one year:				
Trade debtors		(i)	**521.5**	407.5
Amounts receivable under finance leases	US	(ii), (iii)	**14.6**	28.3
Less non-recourse financing			**(7.4)**	(16.1)
			7.2	12.2
Amounts receivable under finance leases	UK	(iii)	**0.1**	0.1
Prepayments and accrued income		(iv)	**689.5**	538.2
Other debtors		(v)	**473.5**	390.9
			1,691.8	1,348.9
(b) Amounts falling due after more than one year:				
Amounts receivable under finance leases	US	(ii), (iii)	**134.9**	171.9
Less non-recourse financing			**(57.9)**	(93.4)
			77.0	78.5
Amounts receivable under finance leases	UK	(iii)	**3.8**	4.0
Other debtors			**18.7**	35.3
			1,791.3	1,466.7

(i) Trade debtors are stated net of provisions for doubtful debts of £60.6 million (2004 £57.9 million).

(ii) The group s finance lease assets in the US which are financed by non-recourse borrowing qualify for linked presentation under FRS 5. The provider of the finance has agreed in writing in the finance documentation that it will seek repayment of the finance, as to both principal and interest, only to the extent that sufficient funds are generated by the specific assets it has financed and that it will not seek recourse in any other form. The directors confirm that the group has no obligation to support any losses arising under these leases nor is there any intention to do so.

(iii) Amounts receivable under finance leases falling due after more than one year at 31 March 2005 of £138.7 million (2004 £175.9 million) are due as follows: within 1-2 years, £15.4 million (2004 £21.4 million); within 2-3 years, £21.6 million (2004 £28.6 million); within 3-4 years, £21.0 million (2004 £23.9 million); within 4-5 years, £10.7 million (2004 £18.1 million) and after 5 years, £70.0 million (2004 £83.9 million). Amounts received under finance leases during the year were £44.0 million (2004 £43.2 million).

(iv) Prepayments and accrued income comprise prepayments of £62.6 million (2004 £48.5 million) and accrued income of £626.9 million (2004 £489.7 million).

(v) Included within other debtors falling due within one year is an amount of £80.3 million (2004 £201.1 million) relating to the value of net investment cross-currency swaps and £39.9 million (2004 £59.3 million) relating to net investment forward contracts as disclosed in Note 20(b).

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20 Loans and other borrowings

Details of the group s objectives, policies and strategy with regard to financial instruments and risk management are contained within the Financial Review on pages 36 to 72. The analyses of financial instruments in this Note, other than currency disclosures, do not include short-term debtors and creditors as permitted by FRS 13.

(a) Analysis by instrument	Notes	Weighted average interest rate 2005	Weighted average interest rate 2004	2005 £m	2004 £m
Unsecured debt of UK businesses					
Bank overdraft					0.1
Uncommitted bank loans		**4.2%**	3.8%	**7.2**	108.0
Medium-term notes/private placements	(i)	**5.8%**	5.4%	**963.6**	1,023.4
Loan notes	(ii)	**4.8%**	3.7%	**1.1**	1.2
European Investment Bank loans	(iii)	**5.9%**	5.9%	**199.2**	199.2
4.000% US dollar convertible bonds	(iv)	**4.4%**	4.4%	**365.4**	374.7
5.250% deutschmark bond 2008		**6.8%**	6.8%	**246.1**	246.0
6.625% euro-sterling bond 2010		**6.7%**	6.7%	**198.8**	198.6
4.910% US dollar bond 2010	(v)	**5.0%**		**289.9**	
Variable rate Australian dollar bond 2011		**5.4%**	4.4%	**235.1**	234.7
5.375% US dollar bond 2015	(v)	**5.1%**		**325.1**	
8.375% euro-sterling bond 2017		**8.5%**	8.5%	**198.0**	197.8
6.750% euro-sterling bond 2023		**6.8%**	6.8%	**247.3**	247.3
5.810% US dollar bond 2025	(v)	**5.9%**		**183.5**	
Unsecured debt of US businesses					
Bank overdraft				**20.5**	20.0
Commercial paper	(vi)	**2.9%**	1.1%	**248.0**	68.0
Pollution control revenue bonds	(vii)	**2.5%**	1.8%	**178.7**	183.7
Finance leases	(viii)	**11.9%**	11.9%	**14.0**	15.0
Other borrowings		**2.9%**	1.1%	**9.8**	11.3
Unsecured debt				**3,931.3**	3,129.0
Secured debt of US businesses					
First mortgage and collateral bonds	(ix)	**7.0%**	7.2%	**1,636.5**	1,601.8
Pollution control revenue bonds	(vii)	**3.3%**	2.6%	**209.7**	215.6
Other secured borrowings	(x)	**6.9%**	6.9%	**117.3**	125.4
Secured debt				**1,963.5**	1,942.8
				5,894.8	5,071.8
Loans and other borrowings are repayable as follows:					
Within one year, or on demand				**553.4**	410.7
After more than one year				**5,341.4**	4,661.1
				5,894.8	5,071.8

(i) Medium-term notes/private placements

Scottish Power plc and Scottish Power UK plc have an established joint US$7.0 billion (2004 US$7.0 billion) euro-medium-term note programme. Scottish Power plc has not yet issued under the programme. Paper is issued in a range of currencies and swapped back into sterling. As at 31 March 2005, maturities range from 1 to 35 years.

(ii) Loan notes

All loan notes are redeemable at the holders discretion. The ultimate maturity date for loan notes currently outstanding is 2006.

(iii) European Investment Bank (EIB) loans

These loans incorporate agreements with various interest rates and maturity dates. The maturity dates of these arrangements range from 2009 to 2011.

(iv) US dollar Convertible bonds

Scottish Power Finance (Jersey) Limited (the Issuer) has issued US$700 million 4.00% step-up perpetual subordinated convertible bonds guaranteed by Scottish Power plc. The bonds are convertible into redeemable preference shares of the Issuer which will be exchangeable immediately on issuance for ordinary shares in Scottish Power plc. The Exchange Price was initially set at £4.60 but will be subject to change on the occurence of certain events set out in the Offering Circular, including payment of dividends greater than amounts set out in the bond agreement, capital restructuring and change of control. The exchange rate to be used to convert US dollar denominated preference shares into sterling is 1.6776. Conversion of the bonds into shares is at the option of the bondholders. During the period up to 3 July 2011, they can opt to convert the bonds into preference shares of the Issuer which are immediately exchangeable into ordinary shares of Scottish Power plc. If the bonds remain outstanding after 10 July 2011, they will bear interest at a rate of 4.00% per annum above the London Inter Bank Offer Rate for three month US dollar deposits. The bonds are perpetual, so there is no fixed redemption date. There are, however, occasions where redemption may occur. The Issuer may redeem the bonds: i) if, after 10 July 2009, for the preceeding 30 dealing days the average of the middle market quotations of an ordinary share has been at least 130% of the average Exchange Price; ii) if, at any time, conversion rights have been exercised and/or purchases effected in respect of 85% or more in principal amount of the bonds; or iii) at any time after 10 July 2011, provided all of the outstanding bonds are redeemed. Under ii) and iii), the redemption amount will be principal value plus accrued, unpaid interest. Under i), the redemption will be by way of the issue of shares. The bondholders may require redemption if an offer is made to the shareholders of Scottish Power plc to buy their shares in the company. The redemption amount will be principal value plus accrued, unpaid interest.

(v) US dollar $4.0 billion US shelf registration

In March 2005 Scottish Power plc established a US$4.0 billion US shelf registration for the issuance of debt and other securities. An inaugural issue of $1.5 billion of bonds was made during the month. These bonds were split into three maturities of 5, 10 and 20 years, with respective notional values being $550 million, $600 million and $350 million.

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20 Loans and other borrowings continued

(vi) Commercial paper

Scottish Power UK plc has an established US$2.0 billion (2004 US$2.0 billion) euro-commercial paper programme. Paper was issued in a range of currencies and swapped back into sterling. No issues have been made under the programme since April 2002. PacifiCorp has a US$1.5 billion (2004 US$1.5 billion) domestic commercial paper programme. Amounts borrowed under the commercial paper programmes are repayable in less than one year.

(vii) Pollution control revenue bonds

These are bonds issued by qualified tax exempt entities to finance, or refinance, the cost of certain pollution control, solid waste disposal and sewage facilities. PacifiCorp has entered into agreements with the issuers pursuant to which PacifiCorp received the proceeds of the issuance and agreed to make payments sufficient to pay principal of, interest on, and certain additional expenses. The interest on the bonds is not subject to federal income taxation for most bondholders. In some cases, PacifiCorp has issued first mortgage and collateral bonds as collateral for repayment.

(viii) Finance leases

These are facility leases that are accounted for as capital leases, maturity dates range from 2014 to 2022.

(ix) First mortgage and collateral bonds

First mortgage and collateral bonds of PacifiCorp may be issued in amounts limited by its Electric operation s property, earnings and other provisions of the mortgage indenture. Approximately US$13.1 billion of the eligible assets (based on original costs) of PacifiCorp is subject to the lien of the mortgage.

(x) Other secured borrowings

Included within other secured borrowings is ScottishPower s share of debt in a joint arrangement for the Klamath co-generation plant. The borrowings are the subject of a guarantee, for US$60.0 million, provided by PacifiCorp Holdings Inc. in respect of second lien revenue bonds.

	At 31 March 2005		At 31 March 2004	
	Book amount	**Fair value**	Book amount	Fair value
(b) Fair value of financial instruments	**£m**	**£m**	£m	£m
Short-term debt and current portion of long-term debt	**547.1**	**547.1**	411.1	411.1
Long-term debt	**5,376.3**	**5,818.4**	4,686.2	5,166.9
Cross-currency swaps	**(28.6)**	**(44.9)**	(25.5)	(43.2)
Total debt	**5,894.8**	**6,320.6**	5,071.8	5,534.8
Interest rate swaps	**(4.1)**	**(31.7)**	(6.4)	16.1
Interest rate swaptions	**2.6**	**1.5**	2.6	2.4
Forward contracts	**(46.4)**	**(81.0)**	(1.9)	(70.0)
Net investment forward contracts	**(39.9)**	**(28.1)**	(59.3)	(47.4)
Net investment cross-currency swaps	**(80.3)**	**(76.5)**	(201.1)	(177.6)
Energy hedge contracts		**(31.8)**		5.1
Energy trading contracts	**(5.7)**	**(5.7)**	(0.6)	(0.6)
Total financial instruments	**5,721.0**	**6,067.3**	4,805.1	5,262.8

The assumptions used to estimate fair values of financial instruments are summarised below:

(i) For short-term borrowings (uncommitted borrowing, commercial paper and short-term borrowings under the committed facilities), the book value approximates to fair value because of their short maturities.

(ii) The fair values of all quoted euro bonds are based on their closing clean market price converted at the spot rate of exchange as appropriate.

(iii) The fair values of the EIB loans have been calculated by discounting their future cash flows at market rates adjusted to reflect the redemption adjustments allowed under each agreement.

(iv) The fair values of unquoted debt have been calculated by discounting the estimated cash flows for each instrument at the appropriate market discount rate in the currency of issue in effect at the balance sheet date.

(v) The fair values of the sterling interest rate swaps and sterling forward rate agreements have been estimated by calculating the present value of estimated cash flows.

(vi) The fair values of the sterling interest rate swaptions are estimated using the sterling yield curve and implied volatilities as at 31 March.

(vii) The fair values of the cross-currency swaps have been estimated by adding the present values of the two sides of each swap. The present value of each side of the swap is calculated by discounting the estimated future cash flows for that side, using the appropriate market discount rates for that currency in effect at the balance sheet date.

(viii) The fair values of the forward contracts are estimated using market forward exchange rates on 31 March.

(ix) The fair values of electricity and gas forwards and futures are estimated using market forward commodity price curves as at 31 March.

(x) The fair values of weather derivatives have been estimated assuming for water related derivatives a normal water year in several water basins, and for temperature related derivatives a normal daily high temperature of certain cities in the US.

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20 Loans and other borrowings continued

(c) Maturity analysis of financial liabilities	**2005** **£m**	2004 £m
Repayments fall due as follows:		
Within one year, or on demand	**553.4**	410.7
Between one and two years	**213.9**	278.2
Between two and three years	**90.1**	227.6
Between three and four years	**611.7**	91.5
Between four and five years	**1,047.0**	616.6
More than five years	**3,378.7**	3,447.2
	5,894.8	5,071.8

Finance leases are included within each of the repayment categories listed above as follows; within one year or on demand £nil (2004 £nil), between one and two years £0.2 million (2004 £0.1 million), between two and three years £0.3 million (2004 £0.3 million), between three and four years £0.3 million (2004 £0.3 million), between four and five years £0.5 million (2004 £0.3 million) and in more than five years £12.7 million (2004 £14.0 million).

The minimum future finance lease payments in relation to the above are as follows; within one year or on demand £1.7 million (2004 £1.8 million), between one and two years £1.8 million (2004 £1.9 million), between two and three years £1.9 million (2004 £2.0 million), between three and four years £1.9 million (2004 £2.0 million), between four and five years £2.0 million (2004 £2.0 million) and in more than five years £22.7 million (2004 £26.4 million). These payments include interest charges allocated to future years of £18.0 million (2004 £21.1 million).

Liabilities:	2006 £m	2007 £m	2008 £m	2009 £m	2010 £m	Thereafter £m	**Total** **£m**	**Fair Value*** **£m**
Fixed rate (GBP)		100.0	25.0	55.0	246.9	841.0	**1,267.9**	**1,420.7**
Average interest rate (GBP)		6.5%	6.7%	5.5%	6.6%	6.7%	6.6%	
Fixed rate (USD) UK group					655.3	558.0	**1,213.3**	**1,248.4**
Average interest rate (USD) UK group					4.4%	5.4%	4.9%	
Fixed rate (USD) US group	144.4	113.9	65.1	216.8	75.0	1,216.0	**1,831.2**	**2,033.5**
Average interest rate (USD) US group	7.4%	7.6%	7.7%	6.1%	7.7%	6.8%	6.9%	
Fixed rate (CZK)	45.9						**45.9**	**45.9**
Average interest rate (CZK)	6.9%						6.9%	
Fixed rate (EUR)				292.9			**292.9**	**312.0**
Average interest rate (EUR)				5.2%			5.2%	
Index-linked (GBP)						201.4	**201.4**	**223.7**
Average interest rate (GBP)						3.49 x RPI	3.49 x RPI	
Variable rate (GBP)	8.3			30.0	57.0		**95.3**	**95.3**
Average interest rate (GBP)	2m LIBOR			6m LIBOR	3m LIBOR		4m LIBOR	
Variable rate (USD) UK group	52.9			18.5			**71.4**	**71.4**
Average interest rate (USD) UK group	3m LIBOR			3m LIBOR			3m LIBOR	
Variable rate (USD) US group	278.3					286.6	**564.9**	**564.9**

Average interest rate (USD) US group	1m LIBOR			BMA	BMA	
Variable rate (USD) US group				38.5	**38.5**	**38.5**
Average interest rate (USD) US group				MCBY	MCBY	
Variable rate (AUD)				263.5	**263.5**	**273.3**
Average interest rate (AUD)				3m BBSW	3m BBSW	
Variable rate (EUR)		6.2	13.7		**19.9**	**20.6**
Average interest rate (EUR)		3m LIBOR	6m LIBOR		5m LIBOR	
Variable rate (JPY)	17.3				**17.3**	**17.3**
Average interest rate (JPY)	6m LIBOR				6m LIBOR	
Total debt					**5,923.4**	**6,365.5**
Cross-currency swaps	6.3	(7.7)	(0.9)	(26.3)	**(28.6)**	**(44.9)**
					5,894.8	**6,320.6**

The disclosures represent the interest profile and currency profile of financial liabilities before the impact of derivative hedging instruments.

The average variable rates above, LIBOR, exclude margins. LIBOR is the London Inter Bank Offer Rate.
GBP Pounds Sterling, USD American Dollars, CAD Canadian Dollars, CZK Czech Koruna, DKK Danish Krone, EUR Euros, JPY Japanese Yen, AUD Australian Dollars. BMA is a weekly high grade market index comprised of 7-day tax exempt variable rate demand notes produced by municipal market data. MCBY is the Moody s Corporate Bond Yield. It is derived from the pricing data of 100 corporate bonds in the US market, each with current outstandings of over $100 million and maturities of 30 years. BBSW is the Australian Bank Bill Rate.

Reference to m in m LIBOR and m BBSW represents months.

* Fair value represents the fair value of the total debt excluding the fair value of related cross-currency swaps, details of which are set out in Note 20(g).

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20 Loans and other borrowings continued

(d) Interest rate analysis of financial liabilities	At 31 March 2005 GBP £m	USD £m	Total £m	At 31 March 2004 GBP £m	USD £m	Total £m
Fixed rate borrowings	**1,285.4**	**2,995.1**	**4,280.5**	1,331.0	2,181.1	3,512.1
Floating rate borrowings	**1,010.9**	**603.4**	**1,614.3**	1,125.3	434.4	1,559.7
	2,296.3	**3,598.5**	**5,894.8**	2,456.3	2,615.5	5,071.8

	Weighted average interest rate at which borrowings are fixed				Weighted average period for which interest rate is fixed			
	At 31 March 2005		At 31 March 2004		At 31 March 2005		At 31 March 2004	
	GBP %	USD %	GBP %	USD %	GBP Years	USD Years	GBP Years	USD Years
Fixed rate borrowings	**6.7**	**6.1**	6.8	6.6	**10**	**10**	10	9

All amounts in the analysis above take into account the effect of interest rate swaps and currency swaps used to convert underlying debt into sterling. This does not include currency swaps used as part of the hedging of the US net investment. Floating rate borrowings bear interest at rates based on LIBOR, certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates. The average interest rates on short-term borrowings as at 31 March 2005 were as follows: GBP 4.7%, USD 2.9% (2004 4.1% and 1.2%