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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM SE

FORM FOR SUBMISSION OF PAPER FORMAT EXHIBITS BY ELECTRONIC FILERS

RECD S.E.C.
JUL 31 2002
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Scottish Power plc
1 Atlantic Quay
GLASGOW, G28SP
SCOTLAND UK
(Exact Name of Registrant as Specified in Charter)

0001045513
(Registrant CIK Number)

PROCESSED
AUG 01 2002
THOMSON
FINANCIAL

FORM U5S FOR 3-31-02
Under the Public Utility
Holding Company Act of 1935

30-312
(SEC file number, if available)

Orlan M. Johnson
Milbank, Tweed, Hadley & McCloy
1825 Eye Street N.W. Suite 1100
Washington, D.C. 20006
(Name of Person Filing the Document
if Other Than the Registrant)

Filed under cover of this Form SE is the exhibit listed on the attached exhibit list.

SIGNATURES

After reasonable inquiry, and to the best of my knowledge and belief, I certify on July 31, 2002 that the information set forth in this statement is true and complete.

By: ______________________
Orlan M. Johnson
Milbank, Tweed, Hadley & McCloy
1825 Eye Street N.W. Suite 1100
Washington, D.C. 20006

Exhibit List

Exhibit Number	Exhibit
Attachment 1	Investment in System Companies
Attachment 2	Remuneration Report of the ScottishPower Officers and Directors
Attachment 3	Affiliated Services Details
Attachment 4	Organization Chart Showing FUCO Relationship
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Exhibit G	Financial Data Schedule
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INVESTMENTS IN SYSTEM SECURITIES

PACIFICORP HOLDINGS, INC. AND SUBSIDIARY COMPANIES

Name of Issuer	Shares Held By	Title of Issue	Original Cost	Authorized Shares	Number of Shares Issued	3/31/02 Owner's/Issuer's Book Value
PACIFICORP HOLDINGS, INC.	N.A. General Partnership	Common	100	10,000	9,113.705	5,523,717,133
PacifiCorp	PacifiCorp Holdings, Inc.	Common, No Par	N/A	750,000,000	297,324,604	2,915,236,751
PacifiCorp Power Marketing Inc.	PacifiCorp Holdings, Inc.	Common	1,000	1,000	100	-60,732,442
Pacific Klamath Energy, Inc.	PacifiCorp Holdings, Inc.	Common	50,000	1,000	50	6,159,090
PacifiCorp Group Holdings Co.	PacifiCorp Holdings, Inc.	Common	N/A	1,000	100	352,474,050

Name of Issuer	Shares Held By	Title of Issue	Original Cost	Authorized Shares	Number of Shares Issued	3/31/02 Owner's/Issuer's Book Value
PACIFICORP						
Centralia Mining Co.	PacifiCorp	Common	1,000	500	100	1,000
Energy West Mining Company	PacifiCorp	Common	1,000	50,000	100	1,000
Glenrock Coal Co.	PacifiCorp	Common	1	100	100	1
Interwest Mining Co.	PacifiCorp	Common	1,000	1,000	100	1,000
Pacific Minerals, Inc.	PacifiCorp	Common, No Par	500	500	500	60,588,382
Bridger Coal Co. (2/3)	Pacific Minerals, Inc.	*	N/A			N/A
PacifiCorp Environmental Remediation Co.	PacifiCorp (8,900) & PacifiCorp Investment Mgt. (1,000)	Common	900,000	10,000	9,900	4,108,435
PacifiCorp Future Generations, Inc.	PacifiCorp	Common	10	1000	10	-2,548
Canopy Botanicals, Inc. (Delaware) (77.85%)	PFGI	Common	251	100,000	25,102	-1,861
Canopy Botanicals, S.R.L. (49%)	CBI	*	N/A			N/A
Noel Kempff Mercado Climate Action Project (NKCAP)	CB,S.R.L	*	N/A			N/A
Rio Bravo Carbon Sequestration Pilot Project	CB,S.R.L.	*	N/A			N/A
Pacific Power & Light Company	PacifiCorp	Common	N/A			100
PacifiCorp Investment Management, Inc.	PacifiCorp	Common	100,000	1,000	100	0
PacifiCorp Capital I (Trust)	PacifiCorp	Quarterly Interest Preferred Securities	6,712,000		8,680,000	6,712,000
PacifiCorp Capital II (Trust)	PacifiCorp	Quarterly Interest Preferred Securities	4,176,000		5,400,000	4,176,000

Name of Issuer	Shares Held By	Title of Issue	Original Cost	Authorized Shares	Number of Shares Issued	3/31/02 Owner's/Issuer's Book Value
PacifiCorp Group Holdings Company						
PacifiCorp Financial Services, Inc.	PGHC		N/A			67,939,887
PacifiCorp International Group Holdings Company	PGHC	Common	112,743,876	100	100	3,430,264
PacifiCorp Trans, Inc.	PGHC	Common	5,000,000	1,000	100	287,285
New Energy Holdings I, Inc.	PGHC	Common	0	1,000	10	0
Energy Works Holdings I, Inc.	New Energy Holdings I, Inc.	Common	132,847	50,000	50,000	0
PT Energy Works Indonesia (.05%)	Energy Works Holdings I, Inc.	*	0			N/A
New IndiaPower Company One (Mauritius) (50%)	Energy Works Holdings I, Inc.	*	0			N/A
Energy Works India Co. Pvt. Ltd. (India) (99.9%)	New India Power Company One	*	0			N/A
New India Power Company Two (Mauritius) (49%)	Energy Works Holdings I, Inc.	*	0			N/A
Energy Works India Co. Pvt. Ltd. (India) (0.1%)	New India Power Company Two	*	0			N/A
New IndioPower Investment Co. Ptd. Ltd. (Singapore) (50%)	Energy Works Holdings I, Inc.	*	0			N/A
PT Energy Works Indonesia (99.95%)	New IndioPower Investment Co.	*	0			N/A
PACE Group, Inc.	PGHC	Common	5,739,361	500	100	0
Pacific Kinston Energy, Inc.	PGHC	Common	200,000	1,000	1	0
PacifiCorp Development Company	PGHC	Common	1,619,017	1,000	10	0
PacifiCorp Generation Int'l, BV	PacifiCorp Dev. Co.	1,000 NLG	2,923,000	40	40	0
Pacific Bakun Energy BV	PacifiCorp Generation Int'l,BV	*	0			N/A
PacifiCorp Energy Inc.	PGHC	Common	0	1,000	100	0

Name of Issuer	Shares Held By	Title of Issue	Original Cost	Authorized Shares	Number of Shares Issued	3/31/02 Owner's/Issuer's Book Value
PacifiCorp Energy Services, Inc.	PGHC	Common	0	1,000	10	0
Encorp	PacifiCorp Energy Services, Inc.	*	1,750,000			0
PacifiCorp Energy Ventures, Inc.	PGHC	Common	1,016,000	1,000	10	0
Black Light	PacifiCorp Energy Ventures, Inc.	*	1,000,000			0
Intellogis	PacifiCorp Energy Ventures, Inc.	*	1,003,333			0
Maxwell Energy	PacifiCorp Energy Ventures, Inc.	*	300,000			0
Nth Power Management, LP	PacifiCorp Energy Ventures, Inc.	*	250,000			0

Name of Issuer	Shares Held By	Title of Issue	Original Cost	Authorized Shares	Number of Shares Issued	3/31/02 Owner's/Issuer's Book Value
PACIFICORP FINANCIAL SERVICES, INC.						
Birmingham Syn Fuel I, Inc.	PFS	Common	1,059,000	1,000	100	28,842,534
CS Holdings, Inc.	PFS	Common	N/A	100,000	1,000	-8,208,262
Koala FSC, Ltd.	PFS	Common	131,142,000	1,200	1,200	-33,211,550
Leblon Sales Corporation	PFS	Common	22,069,000	1,000	1,000	-35,947,106
Pacific Development (Property), Inc.	PFS	Common	N/A		1	-3,611,679
Pacific Harbor Capital, Inc.	PFS	Common	N/A	1,000	407	51,774,616
PFI International, Inc.	Pacific Harbor Capital, Inc.	Common	N/A	1,000	1,000	1,466
PHC Properties Corporation	Pacific Harbor Capital, Inc.	Common	N/A	1,000	100	-86,428
PCC Holdings, Inc.	PFS	Common Preferred	108,000	500 1	1 0	-4,048,320
PacifiCorp Capital, Inc.	PCC Holdings, Inc.	*	N/A			-7,018
Hillsborough Leasing Services, Inc.	PCC Holdings, Inc.	Common	N/A	1	1	0
PNF Holdings, Inc.	PFS	Common	N/A	1,000	100	794,969
VCI Acquisition Co.	PFS	Common Preferred	N/A	5,000 5,000	100 0	0

Name of Issuer	Shares Held By	Title of Issue	Original Cost	Authorized Shares	Number of Shares Issued	3/31/02 Owner's/Issuer's Book Value
PACIFICORP INTERNATIONAL GROUP HOLDINGS COMPANY						
PacifiCorp Hazelwood Pty. Ltd.	PIGHC	*	N/A			50,181
Hazelwood Australia, Inc.	PacifiCorp Hazelwood Pty. Ltd	Common	N/A	500	100	50,181
Hazelwood Ventures, Inc.	Hazelwood Australia, Inc.	Common	N/A	500	100	50,181
Hazelwood Finance LP (12.55%)	Hazelwood Ventures, Inc.	*	N/A			50,181
PacifiCorp Philippines Development Corp.	PIGHC	Common	1,333,085	50,000	10,000	0
PacifiCorp UK Development Corp.	PIGHC	Common	418,409	50,000	10,000	0

Name of Issuer	Shares Held By	Title of Issue	Original Cost	Authorized Shares	Number of Shares Issued	3/31/02 Owner's/Issuer's Book Value
PACIFICORP POWER MARKETING, INC.						
Phoenix Wind Power LLC (formerly PPM1 LLC)	PPM	*	N/A			457,715
MAIN Wind I LLC	PPM	*	N/A			0
MAPP Wind I LLC	PPM	*	N/A			0
Klamath Energy, LLC	PPM	*	N/A			0
Klamath Generation, LLC	PPM	*	N/A			0
West Valley Leasing, LLC	PPM	*	N/A			0
West Valley Generation, LLC	PPM	*	N/A			0
Enstor, Inc.	PPM	*	N/A	1,000	1,000	500,000
City Gate, LLC	Enstor, Inc.	*	N/A			0
Columbia Gas Storage, LLC	Enstor, Inc.	*	N/A			0
Delta Gas Storage, LLC	Enstor, Inc.	*	N/A			0
Enstor Louisiana LLC (formed 4/18/02)	Enstor, Inc.	*	N/A			0
Brentwood Gas Storage LLC (formerly Enstor California LLC - formed 4/19/02)	Enstor, Inc.	*	N/A			0

PacifiCorp
Investments in Other Companies
As of March 31, 2002

Name of Owner	Name of Enterprise	Description of Securities	Number of Shares/Units	Principal Amount/ Original Cost	Book Value ($000s)	Amount Pledged as Collateral ($000s)
PacifiCorp Financial Services, Inc.	Comdial Corporation	Common Stock	131,576	723,744	82,893	
PacifiCorp Environmental Remediation Co.	Columbia Short-Term Bond Fund	Mutual Fund	2,383,901	29,295,048	28,821,364	
PacifiCorp (SERP Trust)	Bankers Trust	EAFE Equity Index Fund	13.48	967,228	647,149	
PacifiCorp (SERP Trust)	Bankers Trust	Equity 500 Index Fund	170.07	2,637,030	1,936,347	

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* Less than £1k

Information as at 31 March 2002

Name of issuer	Shares held by	Owner's Book Value	Owner's Book Value US Dollar equivalent at $1.4/£1	Number of Shares Held	Class of Share capital	Issuer's Book value	Issuer's Book value US Dollar equivalent at $1.4/£1
	(ie Immediate Parent)	£k	$k			£k	$k
Scottish Power UK plc	Scottish Power plc	592,103	828,944	1,183,983,102	Ordinary shares £0.50	591,992	828,789
ScottishPower NA 1 Limited	Scottish Power plc	158,490	221,886	158,489,452	Ordinary shares £1	158,490	221,886
ScottishPower NA 2 Limited	Scottish Power plc	1,426,405	1,996,967	1,426,405,072	Ordinary shares £1	1,426,405	1,996,967
ScottishPower Inc	Scottish Power UK plc	*	*	100	Common stock	*	*
Caledonian Gas Limited	Scottish Power UK plc	250	350	250,000	Ordinary shares £1	250	350
Camjar plc	Scottish Power UK plc	5,122	7,171	284,060	Ordinary shares £1	5,122	7,171
				151,153	10% cumulative redeemable		
					preference shares £1		
				34,960	10% cumulative convertible		
					preference shares £1		
SaBRe Water Limited	Scottish Power UK plc	*	*	2	Ordinary shares £1	*	*
SP Power Systems	Scottish Power UK plc	11,247	15,746	11,247,000	Ordinary £1 shares	11,247	15,746
Aspen 1 Limited	Scottish Power UK plc	*	*	1	Ordinary £1 shares	*	*
Aspen 4 Limited	Scottish Power UK plc	1,380,803	1,933,124	175,000,002	Ordinary £1 shares	175,000	245,000
Emerald Power Generation Limited	Scottish Power UK plc	*	*	1	Ordinary £1 shares	*	*
Scottish Utility Services Limited	Scottish Power UK plc	*	*	2	Ordinary £1 shares	*	*
ScottishPower Energy Retail Limited	Scottish Power UK plc	55,407	77,570	55,407,000	Ordinary £1 shares	55,407	77,570
ScottishPower Energy Trading Limited	Scottish Power UK plc	2,350	3,290	2,350,000	Ordinary £1 shares	2,350	3,290
ScottishPower Energy Trading (Agency) Limited	Scottish Power UK plc	4,000	5,600	4,000,001	Ordinary £1 shares	4,000	5,600
SP Dataserve Limited	Scottish Power UK plc	17,608	24,651	17,608,000	Ordinary £1 shares	17,608	24,651
SPPT Limited	ScottishPower Telecommunications Limited	*	*	2	Ordinary £1 shares	*	*
ScottishPower Sharesave Trustees Limited	Scottish Power UK plc	*	*	2	Ordinary shares £1	*	*
Spotlight Trading Limited	Camjar plc	*	*	2	Ordinary shares £1	*	*
Telephone Information Service plc	Camjar plc	1,280	1,792	350,000	Ordinary shares £1	350	490
Scottish Power Trustees Limited	Scottish Power UK plc	*	*	2	Ordinary shares £1	*	*
SP Distribution Limited	Scottish Power UK plc	109,600	153,440	109,600,000	Ordinary shares £1	109,600	153,440
SP Gas Limited	Scottish Power UK plc	*	*	2	Ordinary shares £1	*	*
Scottish Power Generation Limited	Scottish Power UK plc	130,700	182,980	130,700,000	Ordinary shares £1	130,700	182,980
ScottishPower Investments Limited	Scottish Power UK plc	100,000	140,000	100,000,000	Ordinary shares £1	100,000	140,000
Beaufort Energy Limited	ScottishPower Generation Limited	*	*	2	Ordinary shares £1	*	*
CRE Energy Limited	Beaufort Energy Limited	*	*	2	Ordinary shares £1	*	*
Caledonian Communications Limited	ScottishPower Investments Limited	*	*	2	Ordinary shares £1	*	*
Genscot Limited	ScottishPower Investments Limited	100	140	100,000	Ordinary shares £1	100	140
SP Manweb PLC	ScottishPower Investments Limited	894,879	1,252,831	108,458,370	Ordinary shares £0.50	894,879	1,252,831
Manweb Holdings Limited	ScottishPower Investments Limited	12,500	17,500	12,500,000	Ordinary shares £1	12,500	17,500
Manweb Contracting Services Limited	Manweb Holdings Limited	1,000	1,400	1,000,000	Ordinary shares £1	1,000	1,400
Manweb Limited	ScottishPower UK plc	*	*	1	Ordinary shares £1	*	*
Manweb Energy Consultants Limited	Manweb Holdings Limited	75	105	75,000	Ordinary shares £1	75	105
Manweb Gas Limited	Manweb Holdings Limited	150	210	150,000	Ordinary shares £1	150	210
Manweb Generation Holdings Limited	ScottishPower Generation Limited	2,100	2,940	2,100,000	Ordinary shares £1	2,100	2,940
Manweb Generation (Winnington) Limited	Manweb Generation Holdings Limited	*	*	1	Ordinary shares £1	*	*
Manweb Pensions Trustee Limited	Manweb Holdings Limited	*	*	2	Ordinary shares £1	*	*
Manweb Services Limited	SP Manweb plc	75	105	75,000	Ordinary shares £1	75	105

Securities and Exchange Commission
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Item 1 System Companies and Investments Therein

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* Less than £1k

Information as at 31 March 2002

Name of issuer	Shares held by (ie Immediate Parent)	Owner's Book Value £k	Owner's Book Value US Dollar equivalent at $1.4/£1 $k	Number of Shares Held	Class of Share capital	Issuer's Book value £k	Issuer's Book value US Dollar equivalent at $1.4/£1 $k
Manweb Nominees Limited	SP Manweb plc	*	*	100	Ordinary shares £1	*	*
Manweb Share Scheme Trustees Limited	SP Manweb plc	*	*	2	Ordinary shares £1	*	*
ScotPower Limited	ScottishPower Investments Limited	*	*	2	Ordinary shares £1	*	*
Scotsgrid Limited	ScottishPower Investments Limited	*	*	2	Ordinary shares £1	*	*
Scotspower Limited	ScottishPower Investments Limited	*	*	2	Ordinary shares £1	*	*
ScottishPower Finance Limited	ScottishPower Investments Limited	*	*	2	Ordinary shares £1	*	*
ScottishPower Insurance Limited	ScottishPower Investments Limited	14,500	20,300	9,750,000	Ordinary shares £1	9,750	13,650
ScottishPower Leasing Limited	ScottishPower Investments Limited	*	*	2	Ordinary shares £1	*	*

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* Less than £1k

Information as at 31 March 2002

Name of issuer	Shares held by (ie Immediate Parent)	Owner's Book Value £k	Owner's Book Value US Dollar equivalent at $1.4/£1 $k	Number of Shares Held	Class of Share capital	Issuer's Book value £k	Issuer's Book value US Dollar equivalent at $1.4/£1 $k
ScottishPower Securities Limited	ScottishPower Investments Limited	*	*	2	Ordinary shares £1	*	*
ScottishPower Telecommunications Limited	ScottishPower Investments Limited	15,000	21,000	15,000,000	Ordinary shares £1	15,000	21,000
Demon Internet Limited	ScottishPower Telecommunications Limited	67,600	94,640	1,533,333	Ordinary shares £0.10	67,600	94,640
Cityscape Global Media Limited	Demon Internet Limited	*	*	2	Ordinary shares £1	*	*
Cityscape Internet Services Limited	Demon Internet Limited	*	*	1,000	Ordinary shares £1	*	*
Cityscape Limited	Demon Internet Limited	*	*	2	Ordinary shares £1	*	*
Demon Limited	Demon Internet Limited	*	*	2	Ordinary shares £1	*	*
Dispatch Publishing Limited	Demon Internet Limited	88	123	100	Ordinary shares £1	88	123
Locomotive Software Group Limited	Demon Internet Limited	*	*	200	Ordinary shares £1	*	*
Locomotive Software Developments Limited	Locomotive Software Group Limited	*	*	100	Ordinary shares £1	*	*
Turnpike 1996 Limited	Locomotive Software Group Limited	*	*	100	Ordinary shares £1	*	*
Turnpike Limited	Locomotive Software Group Limited	*	*	100	Ordinary shares £1	*	*
The IP Systems Operations Limited	Demon Internet Limited	*	*	2	Ordinary shares £1	*	*
Lancastrian Holdings Limited	ScottishPower Telecommunications Limited	5,920	8,288	220,022	Ordinary shares £1	5,920	8,288
Megafone (UK) Limited	Lancastrian Holdings Limited	*	*	2	Ordinary shares £1	*	*
Psychic Companions Limited	Lancastrian Holdings Limited	*	*	2	Ordinary shares £1	*	*
Watermark Games Limited	ScottishPower Telecommunications Limited	3,090	4,326	2,949,249	2,949,249 'B' ordinary shares £0.01 each	3,090	4,326
				750	750 'A' ordinary shares £1 each		
SSEB Limited	ScottishPower Investments Limited	*	*	2	Ordinary shares £1	*	*
ScottishPower Share Scheme Trustees Limited	Scottish Power UK plc	*	*	2	Ordinary shares £1	*	*
SP Transmission Limited	Scottish Power UK plc	9,000	12,600	9,000,000	Ordinary shares £1	9,000	12,600
SMW Limited	Scottish Power Generation Limited	*	*	2	Ordinary shares £1	*	*
Southern Water plc	Aspen 4 Limited	1,384,555	1,938,377	156,642,565	Ordinary shares £1	1,380,803	1,933,124
Bowsprit Holdings Limited	Southern Water plc	*	*	100	Ordinary shares £1	*	*
Bowsprit Property Developments Limited	Bowsprit Holdings Limited	*	*	2	Ordinary shares £1	*	*
Monk Rawling Limited	Bowsprit Holdings Limited	*	*	2	Ordinary shares £1	*	*
E S Taylor (Worthing) Holdings Limited	Southern Water plc	503	704	353,572	Ordinary shares £1	353	494
				75,000	Preferred ordinary shares £1	75	105
				75,000	Preference shares £1	75	105
SWS Group Holdings Limited	Southern Water plc	46,300	64,820	100,100	Ordinary shares £1	46,300	64,820
SWS Holdings Limited	SWS Group Holdings Limited	46,300	64,820	100,100	Ordinary shares £1	46,300	64,820
James Leppard & Sons Limited	Southern Water plc	4	6	35	Ordinary shares £1	*	*
				3,500	Deferred ordinary shares £1		
Taylor Plant & Haulage Limited	Southern Water plc	1	1	1,000	Ordinary shares £1	*	*
TES Environmental Services Limited	Southern Water plc	*	*	100	Ordinary shares £1	*	*
Ecoclear Limited	Southern Water plc	2,000	2,800	2,000,100	Ordinary shares £1	2,000	2,800
Linemicro Limited	Southern Water plc	*	*	10,000	Ordinary shares £0.01	*	*
		*	*	2,500	"A" ordinary shares £0.01	*	*
ScottishPower Group Money Purchase Pension Scheme Limited	Southern Water plc	*	*	100	Ordinary shares £1	*	*

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* Less than £1k

Information as at 31 March 2002

							Issuer's
			Owner's Book Value				Book value
		Owner's	US Dollar equivalent	Number of	Class of	Issuer's	US Dollar equivalent
Name of issuer	Shares held by	Book Value	at $1.4/£1	Shares Held	Share capital	Book value	at $1.4/£1
	(ie Immediate Parent)	£k	$k			£k	$k
Teledata Scotland Limited	Teledata (Holdings) Limited	*	*	2	Ordinary shares £1	*	*
The Information Service Limited	Teledata (Holdings) Limited	1,541	2,157	4,073,100	Ordinary shares £1	1,541	2,157
Clubcall Telephone Services Limited	The Information Service Limited	2,068	2,895	2,067,702	Ordinary shares £1	1,899	2,659
Clubline Services Limited	The Information Service Limited	*	*	2	Ordinary shares £1	*	*
Telephone International Media Holdings Limited	Scottish Power UK plc	1,569	2,197	106,250	Ordinary shares £1	1,569	2,197
Copperteam Limited	Telephone International Media Holdings Limited	*	*	2	Ordinary shares £1	*	*
Telephone International Media Limited	Telephone International Media Holdings Limited	650	910	650,000	Ordinary shares £1	650	910
TIM Limited	Telephone International Media Holdings Limited	*	*	2	Ordinary shares £1	*	*

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Information as at 31 March 2002

Name of issuer	Shares held by (ie Immediate Parent)	Owner's Book Value £k	Owner's Book Value US Dollar equivalent at $1.4/£1 $k	Number of Shares Held	Class of Share capital	Issuer's Book value £k	Issuer's Book value US Dollar equivalent at $1.4/£1 $k
Southern Science Limited	Southern Water plc	35	49	35,000	Ordinary shares £1	35	49
Southern Water Executive Pension Scheme Trustees Limited	Southern Water plc	*	*	2	Ordinary shares £1	*	*
Southern Water Industries Limited	Southern Water plc	45	63	45,000	Ordinary shares £1	45	63
Southern Water Pension Trustees Limited	Southern Water plc	*	*	3	Ordinary shares £1	*	*
Southern Water Services Limited	SWS Group Holdings Limited	56	78	56,000	Ordinary shares £1	56	78
Pipeworks Limited	Southern Water plc	*	*	100	Ordinary shares £1	*	*
Southern Water Services Finance plc	Southern Water Services Limited	50	70	50,000	Ordinary shares £1	50	70
Southern Water Technologies Limited	Southern Water plc	*	*	100	Ordinary shares £1	*	*
Timber Clear Limited	Southern Water plc	*	*	100	Ordinary shares £1	*	*
Water Working Limited	Southern Water plc	*	*	100	Ordinary shares £1	*	*
Teledata (Holdings) Limited	Scottish Power UK plc	10,870	15,218	30,000	Ordinary shares £1	10,870	15,218
Teledata (Outsourcing) Limited	Teledata (Holdings) Limited	*	*	100	Ordinary shares £1	*	*
The CallCentre Service Limited	Teledata (Outsourcing) Limited	483	676	4,464,036	Ordinary shares £0.50	483	676
				380,987	Redeemable preference shares £1		

Remuneration Report of the Directors

Introduction

The following statement sets out how, during the financial year ended 31 March 2002, the company has been in compliance with the remuneration principles set out in Part B of the Combined Code. The statement also takes account of the proposals for reform of remuneration disclosure contained in the Department of Trade and Industry Consultative Document on Directors' Remuneration of December 2001.

Consideration of remuneration matters by the directors

The ScottishPower Board is responsible for determining the remuneration policy for the ScottishPower group. The Remuneration Committee determines the detail of remuneration arrangements for executive directors and reviews proposals in respect of other senior executives. The relationship between the Board and the Committee is governed by formal Terms of Reference, which are regularly reviewed and reflect best practice in this field.

The Remuneration Committee consists solely of independent non-executive directors. Its members are Sir Peter Gregson (Chairman), Euan Baird, Mair Barnes, Nolan Karras and Ewen Macpherson. These members have no personal financial interest, other than as shareholders, in the matters considered by the Committee. They are paid a fee and expenses, but do not receive any other remuneration from the company. Details of the payments made to all non-executive directors are set out in Table 26 (page51).

The Terms of Reference require the Chairman of the Committee to attend the Annual General Meeting in order to account to shareholders for the decisions of the Committee.

The Chairman of the company, Charles Miller Smith, and the Chief Executive, Ian Russell, are generally invited to attend meetings and advise, as appropriate, on the performance of executive directors. They are not, however, 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 advised internally by the Group Company Secretary, Andrew Mitchell (who acts as Secretary to the Committee), the Group Director, Human Resources, Michael Pittman, and the Director, Group Remuneration & Benefits, James McInally. The Committee is also provided with independent advice from external remuneration consultants, principally Monks Partnership. The Terms of Reference empower the Committee to avail itself of external legal and professional advice at the expense of the company.

During the year, the Board accepted all of the recommendations from the Committee without significant amendment.

Following the flotation of Thus plc in November 1999, and in accordance with good corporate governance principles, the Thus Board established a separate Remuneration Committee which determines the details of remuneration arrangements for that company. The entire shareholding of ScottishPower in Thus Group plc was demerged to ScottishPower shareholders on 19 March 2002.

Statement of remuneration policy

Philosophy and policy
ScottishPower seeks to ensure that remuneration and incentive schemes are in line with best practice and promote the interests of shareholders.

Rewards for executives and directors should attract and retain individuals of high quality, who have the requisite skills and are incentivised to achieve performance which exceeds that of competitor companies. As such, remuneration packages must be market-competitive. 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. As the company evolves, remuneration packages will be developed to reflect the prevailing market practice in each business environment.

Annual bonus arrangements have been structured so that targets reflect corporate, business unit and individual performance.

The company operates a Personal Shareholding Policy, requiring executives and senior managers to build-up and retain a shareholding in the company in proportion to their annual salaries. These proportions are three times salary for the Chief Executive and two times salary for other executive directors. The Committee considers this policy to be in the best interests of shareholders.

The Committee takes a balanced view of remuneration, considering each element relative to market and, in the past, has realigned elements of the package to reflect market conditions or changes in market practice.

Practical application
In setting remuneration levels, the Committee commissioned an independent evaluation of the roles of the executive, and also of the next levels of management within the company. The Committee has also continued to take independent advice from external remuneration consultants on market-level remuneration, based on comparison with companies of similar size and complexity. In considering the comparator companies, the consultants have included a number of other utilities but have not restricted their study solely to utilities.

Base salaries
The Committee sets the base salary for each executive director by reference to individual performance through a formal appraisal system, and to external market data, based on job evaluation principles and reflecting similar roles in other comparable companies.

Annual performance-related bonus
Executive directors and senior management participate in the company's performance-related pay schemes. All payments under the schemes are non-pensionable and are subject to the approval of the Committee.

The 2001/02 scheme for executive directors provided a bonus opportunity of a maximum of 75% of salary, with half determined by the company's financial performance. The balance of the bonus is linked to each executive's achievement of key strategic objectives, both short-term and long-term. Objectives are set annually by the Board and performance against these is reviewed on a six-monthly basis.

'or the 2001/02 performance year, the xecutive directors indicated that they did ıot wish to be considered for a bonus ›ayment, despite the fact that their personal ›erformance and achievement of strategic ıbjectives would have warranted such a ›ayment under the rules of the Plan. The Committee decided that no bonus should ›e paid to executive directors.

:xecutive share schemes
'he company operates a performance hare plan, the Long Term Incentive Plan "LTIP"), and an Executive Share Option 'lan 2001 ("ExSOP") for executive lirectors and other senior managers.

'he LTIP links the rewards closely ›etween management and shareholders, ınd focuses on long-term corporate ›erformance. Under the current LTIP, ıwards to acquire shares in ScottishPower at nil or nominal cost are nade to the participants up to a naximum value equal to 75% of base alary. The award will vest only if the Committee is satisfied that certain gateway performance measures are met. These relate to the sustained underlying inancial performance of the company ınd performance in relation to customer service standards, including those set by Ofgem and OFWAT.

The number of shares which actually vest is dependent upon the company's comparative total shareholder return ›erformance, over a three-year ›erformance period. For LTIP awards which have vested during the year, this ›erformance is measured against that of the FTSE 100 index and an index of the Electricity and Water sectors of the FTSE All Share Index. For LTIP awards granted during the year, this performance is neasured against a comparator group of 40 international energy companies, as dentified below:

AES Corp; American Electric Power Inc; Calpine Corp; Centrica; Chubu Electric Power Co Inc; CLP Holdings Limited; Constellation Energy Group Inc; Dominion Resources Inc; Duke Energy Corp; Dynegy nc; Edison SpA; Edison International; El Paso Corp; Electricidade de Portugal SA; Electrabel SA; Endesa SA; Enron; 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; Lattice Group plc; National Grid; Powergen; PPL Corp; Progress Energy Inc; Public Service Enterprise Group Inc; Reliant Energy Inc; Scottish & Southern Energy; Southern Company Inc; Tenaga Nasional Bhd; The Tokyo Electric Power Co Inc; TXU; Union Fenosa; Williams Companies Inc; Xcel Energy Inc.

No shares vest unless the company's performance is at least equal to the median performance of the comparator group. 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.

During the 2001/02 year, the company introduced a new ExSOP. Options granted under the ExSOP are 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 Retail Price Index). 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.

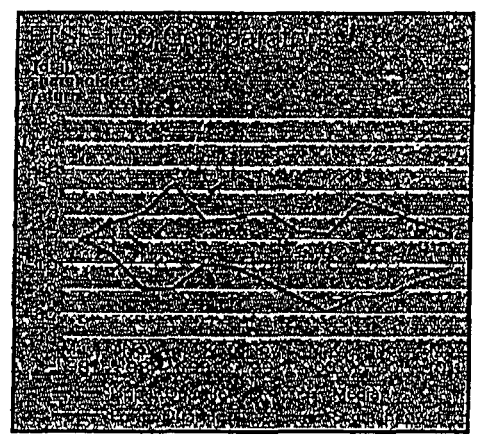
A number of legacy share-based incentive plans are also in place in the company's international operations. These are structured to comply with local tax and legislation and are established at market-competitive levels. No executive director participates in any international share incentive arrangement and no further grants will be made under these plans.

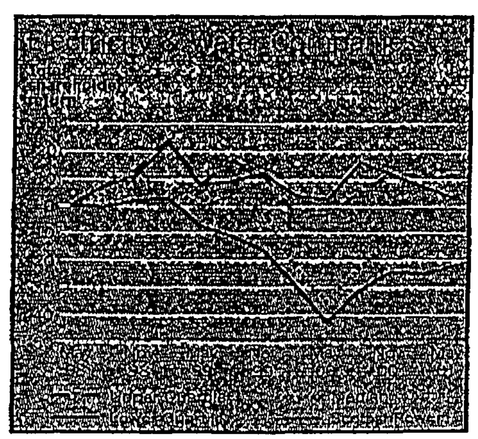
Employee Share Plans
The company operates a savings-related share option scheme, which is open to all UK permanent employees. Under this scheme, options are granted over ScottishPower shares at a discount of 20% from the prevailing market price at the time of grant to eligible employees who agree to save up to £250 per month over a period of three or five years.

In addition, the Government implemented legislation in July 2000 to enable companies to introduce a new Inland Revenue approved Employee Share Ownership Plan ("ESOP"). The company was amongst the first to introduce these arrangements for all UK employees. The ESOP enables employees to purchase shares in the company from pre-tax income up to the limits specified in the legislation. The company matches these shares at no cost to the employee on a one-for-one ratio. The legislation also enables the company to award free shares to employees. No free shares were awarded during 2001/02.

Pension
The executive directors, and other senior managers of the company, are provided

The graphs below represent the comparative Total Shareholder Return (% growth) performance of the company during the performance period for Award 3 of the Long Term Incentive Plan (May 1998 – May 2001) that vested during the financial year.





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.

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 above the cap cannot be provided through the company's approved pension benefits, 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 in respect of executives and senior employees arising in relation to unapproved benefits accrued for service for the year to 31 March 2002 was £690,000. The Trustee body of the Executive Top Up Plan is chaired by the Group Company Secretary.

The Committee has reported the pension expense in accordance with the requirements of the UK Listing Authority. Pension costs detailed in the Accounts are calculated as the cost of providing benefits accrued in 2001/02.

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, fuel, private medical provision and permanent health insurance. Senior executives, depending upon grade, are eligible for certain of these benefits.

As with salary, the level of benefits is reviewed annually through surveys from independent consultants. Practice varies as to the composition of these items amongst the comparator group and the company's benefits are broadly in line with the practice of the group.

To summarise the above, the executive directors are required to meet or exceed performance targets in order to receive bonus payments and to participate in the Long Term Incentive Plan and the Executive Share Option Plan 2001. Their base salaries are set in accordance with market competitive levels and performance assessments. The employee share plans are open to all UK employees. They are essentially savings vehicles and are not subject to a performance test. Pension entitlements and other benefits are not performance related.

Service contracts

ScottishPower has reviewed its policy on service contracts and, in accordance with the best practice recommendation of the Combined Code, has resolved that new appointees to the Board be offered notice periods of one year. The Committee recognises however that it may be necessary, in the case of appointments from outside the company, to offer a longer initial notice period: the intent being to subsequently reduce this period to one year following an agreed initial period.

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.

Executive directors, Charles Berry and David Nish, were appointed to the Board on or after 1 April 1999; these appointments have service contracts terminable on one year's notice from both parties.

Two executive directors appointed before 1 April 1999 had service contracts terminable by the company on two years' notice (this having been reduced from the three year period applicable prior to September 1994) and by the individuals concerned on one year's notice. Ken Vowles retired on 31 March 2002 and accordingly only one executive director, the Chief Executive, Ian Russell, now has a service contract terminable by the company on two years' notice. Given that the Chief Executive agreed, without compensation, to a previous reduction in the notice period in his service contract, the Committee believes that it remains appropriate for him to retain a two-year rolling contract.

External non-executive appointments

The company encourages its directors to become non-executive directors of other companies, provided that these 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.

Remuneration policy for non-executive directors

The remuneration of non-executive directors is determined by the Board and consists of fees for their service in connection with the Board and Board Committees. Additional fees are also payable for chairing Board Committees. The non-executive directors do not have service contracts, are not members of the company's pension schemes and do not participate in any bonus, share option or other profit or long-term incentive scheme. Full details of the remuneration of the non-executive directors are contained in Table 26.

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 was £5,482,058.

During 2001/02 the aggregate amount set aside or accrued by 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 £1,740,336.

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 Schemes and awards under the LTIP, are shown on pages 52 to 54.

Directors' and officers' liability insurance
The company maintains liability insurance for the directors and officers of the company and its subsidiaries.

Directors' emoluments and interests
Total emoluments
Table 26 provides a breakdown of the total emoluments of the Chairman and all the directors in office during the year ended 31 March 2002.

Directors' pension benefits
Details of pension benefits earned by the executive directors during the year are shown in Table 27.

Table 26 - Remuneration of directors during 2001/02

	Basic salary £000's		Bonus £000's		Benefits in kind £000's		Total £000's	
	2002	2001	2002	2001	2002	2001	2002	2001
Chairman and executive directors								
Charles Miller Smith	235.0	235.0	–	–	13.8	4.7	248.8	239.7
Sir Ian Robinson (retired 4 May 2001)	93.3	522.7	–	–	2.9	24.2	96.2	546.9
Ian Russell (appointed Chief Executive 17 April 2001)	542.9	390.0	–	–	27.6	34.6	570.5	424.6
Charles Berry	280.0	220.0	–	–	19.2	19.3	299.2	239.3
David Nish	325.0	225.0	–	–	23.9	28.0	348.9	253.0
Alan Richardson (retired 31 December 2001)*	225.0	245.0	–	–	0.8	0.7	225.8	245.7
Ken Vowles (retired 31 March 2002)	300.0	270.0	–	–	16.0	14.1	316.0	284.1
Total	2,001.2	2,107.7	–	–	104.2	125.6	2,105.4	2,233.3

	Fees £000's		Bonus £000's		Benefits in kind £000's		Total £000's	
	2002	2001	2002	2001	2002	2001	2002	2001
Non-executive directors (fees & expenses)								
Keith McKennon (retired 27 July 2001)	21.3	64.0	–	–	17.4	11.0	38.7	75.0
Euan Baird	28.5	6.5	–	–	0.7	–	29.2	6.5
Mair Barnes	32.0	33.0	–	–	1.0	2.8	33.0	35.8
Philip Carroll (appointed 15 January 2002)	4.4	–	–	–	0.6	–	5.0	–
Sir Peter Gregson	40.5	36.5	–	–	2.8	2.1	43.3	38.6
Nolan Karras**	32.8	33.5	–	–	19.7	6.5	52.5	40.0
Allan Leighton	27.5	6.5	–	–	0.1	0.4	27.6	6.9
Ewen Macpherson	39.5	39.5	–	–	4.0	2.2	43.5	41.7
Robert Miller (resigned 8 June 2001)	6.1	31.5	–	–	2.2	21.0	8.3	52.5
John Parnaby (retired 27 July 2001)	12.8	40.5	–	–	3.9	1.9	16.7	42.4
Total	245.4	291.5	–	–	52.4	47.9	297.8	339.4

Other emoluments
* Alan Richardson received an additional £381,220 (2001 £283,220) in respect of housing, foreign service allowance and other essential costs associated with his assignment as Executive Director, US, based in Portland, Oregon. These costs include relocation and repatriation back to the UK.

** Nolan Karras received emoluments in the US of £22,613 (2001 £26,857) in respect of services to the PacifiCorp and Utah advisory boards in the form of cash and shares.

(i) The emoluments of the highest paid director (Ian Russell) excluding pension contributions were £570,531. In addition, gains on exercise of share awards before tax during the year by Ian Russell amounted to £138,628. The emoluments of the highest paid director in 2000/01 (Sir Ian Robinson) excluding pension contributions were £546,862. Details of other share related incentives are contained in Tables 28 and 29.

(ii) Pension contributions made by the company under approved pension arrangements for Ian Russell amounted to £nil (2001 £nil). Ian Russell also has an entitlement under the unapproved pension benefits described further in Table 27(i).

(iii) Sir Ian Robinson retired from the Board on 4 May 2001 and as an employee on 31 May 2001. Alan Richardson retired from the Board and as an employee on 31 December 2001. Ken Vowles retired from the Board and as an employee on 31 March 2002.

(iv) In addition to the above, payments were made to Sir Ian Robinson of £385,000; Alan Richardson of £372,099; and Ken Vowles of £405,649, in accordance with the terms of their respective contracts. Details of pension scheme entitlements and interests in performance and other share plans are set out overleaf in Tables 27 and 29 respectively.

Table 27 - Defined benefits pension scheme 2001/02

	Transferred – in benefits £ p.a.	Additional pension earned in year £ p.a.	Accrued entitlement £ p.a.	Transfer value of increases after indexation (net of director's contribution) £
Charles Miller Smith	–	–	–	–
Sir Ian Robinson (retired from the Board on 4 May 2001 and from the company on 31 May 2001)	–	–	–	–
Ian Russell	15,094	52,738	144,159	545,011
Charles Berry	–	23,568	82,744	246,993
David Nish	34,938	26,111	67,356	200,946
Alan Richardson (retired 31 December 2001)	–	50,263	130,000	633,959
Ken Vowles (retired 31 March 2002)	127,808	14,346	141,570	231,657

(i) The accrued entitlement of the highest paid director (Ian Russell) was £144,159. In 2001, the accrued entitlement of the highest paid director (Sir Ian Robinson) was £319,200. During the year, retirement benefits were accrued under the defined benefits pension scheme in respect of 5 directors (2001 6 directors). The method of calculation of retirement benefits for Sir Ian Robinson was agreed prior to his retirement and published in last year's Remuneration Report.

(ii) The transfer value of the increases after indexation 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 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 lifetime (and also covering the cost of dependants' benefits after his death).

(iii) With respect to Alan Richardson, the figures shown in the table above reflect the increase in his pension, including contractual changes made to enable his withdrawal. In addition, the value of allowing him to take his retirement benefits immediately was £850,750.

(iv) The pension entitlement shown is that which would be paid annually on retirement based upon service to the end of the year. Members of the group's schemes have the option of paying additional voluntary contributions; neither the contributions nor the resulting benefits are included in the above table.

(v) Executives who joined the company 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 accrued pension during the year allows for an increase in inflation of RPI as measured at December 2001 (0.7%).

(vii) The value of the increase in Members' 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 less directors' contributions; the unapproved element is calculated in line with FRS 17 assumptions.

(viii) Transferred in benefits represent pension rights accrued in respect of previous employments.

(ix) The total liabilities, calculated on an FRS 17 basis, for the 14 executives and senior employees arising in relation to unapproved benefits for service for the year to 31 March 2002 was £690,000 (2001 £500,000). All benefits for the above are provided on a defined benefit basis.

Table 28 – Directors' interests in shares as at 31 March 2002

	Ordinary shares		Share options (Executive)		Share options (Sharesave)		Long Term Incentive Plan			
	31.3.02	1.4.01 (or date of appointment if later)	31.3.02	1.4.01	31.3.02	1.4.01	31.3.02 **Vested	31.3.02 *Potential	1.4.01 **Vested	1.4.01 *Potential
Charles Miller Smith	11,000	11,000	–	–	–	–	–	–	–	–
Ian Russell	•86,817	•58,418	227,743	–	4,371	–	12,682	175,063	27,691	114,694
Charles Berry	•18,958	•14,691	107,660	–	903	2,232	4,433	87,904	9,951	55,461
David Nish	•7,294	•4,112	124,223	–	2,509	2,215	4,191	85,030	–	45,286
Ken Vowles	•143,410	•138,801	124,223	–	3,073	5,501	29,796	109,308	20,768	81,655
Euan Baird	100,000	100,000	–	–	–	–	–	–	–	–
Mair Barnes	1,400	1,400	–	–	–	–	–	–	–	–
Philip Carroll	–	–	–	–	–	–	–	–	–	–
Sir Peter Gregson	1,093	1,024	–	–	–	–	–	–	–	–
Nolan Karras	31,286	27,347	–	–	–	–	–	–	–	–
Allan Leighton	–	–	–	–	–	–	–	–	–	–
Ewen Macpherson	5,000	5,000	–	–	–	–	–	–	–	–

None of the directors has an interest in ordinary shares which is greater than 1% of the issued share capital of the company.

* 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 Long Term Incentive Plan award is exercisable after the fourth anniversary of grant 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
Ian Russell	50	388	388	33	859
Charles Berry	50	388	388	33	859
David Nish	50	388	388	33	859
Ken Vowles	50	388	388	–	826

Between 31 March 2002 and 1 May 2002, Ian Russell, Charles Berry and David Nish each acquired 34 Partnership Shares and 34 Matching Shares as part of the regular monthly transactions of the Employee Share Ownership Plan. Otherwise, there have been no changes in the directors' interests between 31 March 2002 and 1 May 2002.

Table 29 – Directors' interests in performance and other share plans at 31 March 2002

	1 April 2001	Granted	Exercised	Lapsed#	31 March 2002 (or date of retirement as director if earlier)	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	–	–	–	–	–	nil			9 Aug 00	8 Aug 03
	27,691	–	27,691	–	–	nil	29 May 01	500.625	16 May 01	15 May 04
	31,706	–	–	19,024	12,682	nil			7 May 02	6 May 05
	37,988	–	–	–	37,988	nil			10 May 03	9 May 06
	45,000	–	–	–	45,000	nil			5 May 04	4 May 07
	–	92,075	–	–	92,075	nil			4 May 04	3 May 08
	142,385	92,075	27,691	19,024	187,745					
Charles Berry	–	–	–	–	–	nil			9 Aug 00	8 Aug 03
	9,951	–	9,951	–	–	nil	31 May 01	510.25	16 May 01	15 May 04
	11,083	–	–	6,650	4,433	nil			7 May 02	6 May 05
	18,994	–	–	–	18,994	nil			10 May 03	9 May 06
	25,384	–	–	–	25,384	nil			5 May 04	4 May 07
	–	43,526	–	–	43,526	nil			4 May 04	3 May 08
	65,412	43,526	9,951	6,650	92,337					
David Nish	–	–	–	–	–	nil			9 Aug 00	8 Aug 03
	–	–	–	–	–	nil			16 May 01	15 May 04
	10,479	–	–	6,288	4,191	nil			7 May 02	6 May 05
	11,731	–	–	–	11,731	nil			10 May 03	9 May 06
	23,076	–	–	–	23,076	nil			5 May 04	4 May 07
	–	50,223	–	–	50,223	nil			4 May 04	3 May 08
	45,286	50,223	–	6,288	89,221					
Alan Richardson (retired 31 December 2001)	9,661	–	9,661	–	–	nil	9 May 01	455.38	9 Aug 00	8 Aug 03
	10,816	–	10,816	–	–	nil	22 May 01	473.25	16 May 01	15 May 04
	11,446	–	–	6,868	4,578	nil			7 May 02	6 May 05
	18,994	–	–	–	18,994	nil			10 May 03	9 May 06
	25,384	–	–	–	25,384	nil			5 May 04	4 May 07
	–	50,223	–	–	50,223	nil			4 May 04	3 May 08
	76,301	50,223	20,477	6,868	99,179					
Sir Ian Robinson (retired from the Board 4 May 2001 and from the company on 31 May 2001)	36,072	–	–	–	36,072	nil			9 Aug 00	8 Aug 03
	40,383	–	–	–	40,383	nil			16 May 01	15 May 04
	41,916	–	–	–	41,916	nil			7 May 02	6 May 05
	46,927	–	–	–	46,927	nil			10 May 03	9 May 06
	58,153	–	–	–	58,153	nil			5 May 04	4 May 07
	223,451	–	–	–	223,451					
Ken Vowles (retired 31 March 2002)	–	–	–	–	–	nil			9 Aug 00	8 Aug 03
	20,768	–	–	–	20,768	nil			16 May 01	15 May 04
	22,570	–	–	13,542	9,028	nil			7 May 02	6 May 05
	27,932	–	–	–	27,932	nil			10 May 03	9 May 06
	31,153	–	–	–	31,153	nil			5 May 04	4 May 07
	–	50,223	–	–	50,223	nil			4 May 04	3 May 08
	102,423	50,223	–	13,542	139,104					

On 16 May 2001, the second awards under the Long Term Incentive Plan became exercisable. The mid-market closing price on that day was 487 pence and the value attributable to those awards at that date was £533,796. Details of awards exercised are shown in the table above.

During the year, the performance period for awards granted under the Long Term Incentive Plan in 1998 ended and, on the basis of the company's total shareholder return, 40% of shares under awards vested. However, awards may not be exercised until the fourth anniversary of the grant and are exercisable until the seventh anniversary.

In accordance with the rules of the Long Term Incentive Plan, retiring directors are entitled to retain a portion of Long Term Incentive Plan awards. However, following retirement, these remain subject to the performance criteria detailed in (ii) below.

As a result of the retirement of Sir Ian Robinson from the company on 31 May 2001 and in accordance with the rules of the Long Term Incentive Plan, 19,385 shares under the award of 58,153 shares granted in 2000 lapsed leaving a balance of 38,768. On 7 May 2001, 25,150 shares under the award of 41,916 shares granted in 1998 lapsed leaving a balance of 16,766 shares.

As a result of the retirement of Alan Richardson from the company on 31 December 2001 and in accordance with the rules of the Plan, 3,526 shares under the award of 25,384 shares granted in 2000 lapsed leaving a balance of 21,858 shares and 23,717 shares under the award of 50,223 shares granted in 2001 lapsed, leaving a balance of 26,506 shares.

As a result of the retirement of Ken Vowles from the company on 31 March 2002 and in accordance with the rules of the Plan, 2,791 shares under the award of 50,223 shares granted in 2001 lapsed, leaving a balance of 47,432 shares.

Footnote

Awards granted to directors under the Long Term Incentive Plan on 2 May 2002 were as follows: Ian Russell 101,600; Charles Berry 55,418; and David Nish 64,655.

Table 29 – Directors' interests in performance and other share plans at 31 March 2002 continued

	1 April 2001	Granted	Exercised	Lapsed#	31 March 2002 (or date of retirement if earlier)	Option exercise price (pence)	Date exercised	Market price at date of exercise (pence)	Normal date from which exercisable	Normal expiry date
Executive Share Option Plan 2001										
Ian Russell	–	227,743	–	–	227,743	483.0			21 Aug 04	21 Aug 11
	–	**227,743**	–	–	**227,743**					
Charles Berry	–	107,660	–	–	107,660	483.0			21 Aug 04	21 Aug 11
	–	**107,660**	–	–	**107,660**					
David Nish	–	124,223	–	–	124,223	483.0			21 Aug 04	21 Aug 11
	–	**124,223**	–	–	**124,223**					
Alan Richardson (retired 31 December 2001)	–	124,223	–	–	124,223	483.0			21 Aug 04	21 Aug 11
	–	**124,223**	–	–	**124,223**					
Ken Vowles (retired 31 March 2002)	–	124,223	–	–	124,223	483.0			21 Aug 04	21 Aug 11
	–	**124,223**	–	–	**124,223**					
Sharesave Scheme										
Ian Russell	–	4,371	–	–	4,371	386.0			1 Sep 06	28 Feb 07
	–	**4,371**	–	–	**4,371**					
Charles Berry	1,329	–	1,329	–	–	440.0*	3 Sep 01	489.0	1 Sep 01	28 Feb 02
	903	–	–	–	903	429.0*			1 Sep 02	28 Feb 03
	2,232	–	**1,329**	–	**903**					
David Nish	2,215	–	2,215	–	–	440.0*	3 Sep 01	489.0	1 Sep 01	28 Feb 02
	–	2,509	–	–	2,509	386.0*			1 Sep 04	28 Feb 05
	2,215	**2,509**	**2,215**	–	**2,509**					
Alan Richardson (retired 31 December 2001)	1,568	–	–	–	1,568	440.0			1 Sep 03	29 Feb 04
	1,573	–	–	–	1,573	429.0			1 Sep 04	28 Feb 05
	–	874	–	–	874	386.0*			1 Sep 06	28 Feb 07
	3,141	**874**	–	–	**4,015**					
Ken Vowles (retired 31 March 2002)	3,933	–	3,933	–	–	263.1	3 Sep 01	489.0	1 Sep 01	28 Feb 02
	1,568	–	–	–	1,568	440.0			1 Sep 03	29 Feb 04
	–	1,505	–	–	1,505	386.0*			1 Sep 04	28 Feb 05
	5,501	**1,505**	**3,933**	–	**3,073**					

*Denotes options granted under a three-year scheme.

(i) The market price of the shares at 28 March 2002 (the last trading day before the financial year end) was 359.50 pence and the range during 2001/02 was 350.00 pence to 521.84 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 improvements in certain Ofgem published Customer Service Standards and OFWAT published levels of service 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 will be dependent upon how the company ranks 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 and a group of international energy companies. A percentage of each half of the award will vest depending upon the company's ranking within each of the comparator groups. The plan participant may acquire the shares in respect of the percentage of the award which has vested at any time after the third or fourth year, as appropriate, up to the seventh year after the grant of the award. No dividends accrue to participants prior to vesting.

(iii) During the year, the Executive Share Option Plan 2001 was launched, whereby options are granted to relevant executives and senior managers. These options are 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 Retail Price Index). 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. In accordance with the Plan rules, directors retiring during the year are entitled to exercise their executive options within 42 months of the date of grant (21 August 2001).

(iv) 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. In accordance with the rules of the Scheme, directors retiring during the year are entitled to exercise Sharesave options within 6 months of the date of their retirement, over the number of shares which can be purchased using their savings plus interest.

(v) 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 three or five years under an Inland Revenue approved savings contract, subject to a current maximum.

(vi) At 1 April 2001, Keith McKennon held options to acquire 145,000 ScottishPower ADSs at an option price of $32.76 exercisable from February 2003 to February 2009. One ScottishPower ADS equates to four ordinary shares, and therefore the option, expressed in ordinary shares, was over 580,000 ordinary shares. He retains these options following retirement on 27 July 2001.

(vii) Total gains made on exercise of directors' share options and awards during the year were £295,205 (2001 £319,599).

Footnote

Options granted to directors under the Executive Share Option Plan 2001 on 2 May 2002 were as follows: Ian Russell 270,935; Charles Berry 147,783; and David Nish 172,413.

:cal Year 2002 AFFILIATE) UTILITY ERVICES	Fiscal Year 2002 BY UTILITY TO AFFILIATE -SERVICES	Fiscal Year 2002 BY AFFILIATE TO UTILITY -INTEREST	Fiscal Year 2002 BY UTILITY TO AFFILIATE -INTEREST	Fiscal Year 2002 TOTAL BY AFFILIATE TO UTILITY	Fiscal Year 2002 TOTAL BY UTILITY TO AFFILIATE	Fiscal Year 2002 TOTAL TRANSACTIONS
-	-	-	18,456,240.00	-	18,456,240.00	18,456,240.00
-	-	-	10,716,552.00	-	10,716,552.00	10,716,552.00
19,879.39	354,656.03	-	-	19,879.39	354,656.03	374,535.42
-	-	-	-	-	-	-
723,498.99	480,780.68	-	-	723,498.99	480,780.68	1,204,279.67
-	-	-	-	-	-	-
-	-	-	-	-	-	-
,226,472.40	112,317.26	-	-	118,226,472.40	112,317.26	118,338,789.66
,793,433.58	11,014,361.47	-	739,488.21	68,793,433.58	11,753,849.68	80,547,283.26
-	177,634.26	-	5,387,078.43	-	5,564,712.69	5,564,712.69
56,745.00	505,341.86	-	-	56,745.00	505,341.86	562,086.86
7,265.85	1,739,293.62	-	-	7,265.85	1,739,293.62	1,746,559.47
-	32,622.86	-	-	-	32,622.86	32,622.86
-	144.27	-	-	-	144.27	144.27
-	58,263.00	-	-	-	58,263.00	58,263.00
,643,996.21	-	-	-	7,643,996.21	-	7,643,996.21
,451,904.16	5,079,178.67	-	-	16,451,904.16	5,079,178.67	21,531,082.83
-	345,075.22	-	-	-	345,075.22	345,075.22
,923,195.58	19,899,669.20	-	35,299,358.64	211,923,195.58	55,199,027.84	267,122,223.42

Affiliated Services Detail
For the Fiscal Year 2002

PacifiCorp Financial Services 3500, 3510, 3520

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		29,505.85
Management Fee	690005		102,674.89
Facilities Services	690006		1,479.94
IT Allocations	690007		2,993.10
Shared Services Chargebacks	690026		387.09
Sub-total		0.00	137,040.87

Pacific Klamath Energy 5320

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		144.27
Management Fee	690005		12,245.64
IT Services Allocations	690025		300.00
Shared Services Chargebacks	690026		2,580.60
Sub-total		0.00	15,270.51

PacifiCorp Environmental Remediation 1040

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000	5,174.40	35,628.81
Benefits	699005		
Semi Tractor	620025		
Management Fee	690005		16,013.57
Facilities Services	690006		5,644.17
IT Allocations	690007		9,709.50
Other Salary OH Assessments	690019		
LTD Assessments	690021		
IT Services Allocations	690025		18,000.00
Shared Services Chargebacks	690026		1,032.24
Sub-total		5,174.40	86,028.29

Affiliated Services Detail
For the Fiscal Year 2002

Components	SAP Acct	PacifiCorp Power Marketing BY AFFILIATE TO UTILITY -SERVICES	4000 BY UTILITY TO AFFILIATE -SERVICES
Labor	699000	7,265.85	109,135.34
Management Fee	690005		53,692.37
Facilities Services	690006		50,081.43
IT Allocations	690007		32,230.50
IT Services Allocations	690025		39,600.00
Shared Services Chargebacks	690026		6,967.62
Sub-total		7,265.85	291,707.26

PacifiCorp Group Holdings
3000, 4350, 4900

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		18,394.11
Facilities Services	690006		
IT Allocations	690007		675.30
LTD Assessments	690021		
IT Services Allocations	690025		14,700.00
Shared Services Chargebacks	690026		
Benefits	690005		
Sub-total		0.00	33,769.41

PacifiCorp Trans
4100

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		5,386.08
IT Allocations	690007		675.30
Vehicle Lease Assessment	690024		1,230.00
Shared Services Chargebacks	690026		129.03
Sub-total		0.00	7,420.41

Affiliated Services Detail
For the Fiscal Year 2002

PacifiCorp Holding Inc.
5000

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		144.27
Sub-total		0.00	144.27

Centralia Mining
2040

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		
IT Allocations	690007		
Fuel Purchased/Sold	1201XX		
Sub-total		0.00	0.00

Energy West Mining
2050

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		1,176.00
IT Allocations	690007		27,687.30
Fuel Purchased/Sold	1201XX	30,173,493.89	
Sub-total		30,173,493.89	28,863.30

Glenrock Coal **2030**

Components	SAP Acct	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
IT Allocations	690007		
Fuel Purchased/Sold	1201XX		
Sub-total		0.00	0.00

Affiliated Services Detail
For the Fiscal Year 2002

Components	SAP Acct	Interwest Mining BY AFFILIATE TO UTILITY -SERVICES	2010 BY UTILITY TO AFFILIATE -SERVICES
Labor	699000	130,858.10	
Facilities Services	690006		21,858.41
IT Allocations	690007		22,430.40
Other Salary OH Assessments	690019		1,104.07
SERP Assessments	690020		21,425.26
LTD Assessments	690021		2,000.77
Incentive Assessments	690022	127,164.30	
IT Services Allocations	690025		38,700.00
Shared Services Chargebacks	690026		3,612.84
Benefits	699005	19,488.99	
Sub-total		277,511.39	111,131.75

Components	SAP Acct	Pacific Minerals Inc. / Bridger Coal BY AFFILIATE TO UTILITY -SERVICES	N/A BY UTILITY TO AFFILIATE -SERVICES
Fuel Purchased/Sold	1201XX	16,829,894.93	
Benefits, Mgmt Fee, & Misc. Billings	116010		2,818,542.00
Royalty Billings	116011		
Sub-total		16,829,894.93	2,818,542.00

Components	SAP Acct	Trapper Mining BY AFFILIATE TO UTILITY -SERVICES	N/A BY UTILITY TO AFFILIATE -SERVICES
Fuel Purchased/Sold	1201XX	1,924,717.22	
Sub-total		1,924,717.22	0.00

Affiliated Services Detail
For the Fiscal Year 2002

Components	SAP Acct	PacifiCorp Foundation BY AFFILIATE TO UTILITY -SERVICES	N/A BY UTILITY TO AFFILIATE -SERVICES
Labor	116020		47,587.33
Benefits	116020		5,554.28
Misc. Other Expenses	116020		20,139.31
Sub-total		0.00	73,280.92

Components	SAP Acct	ScottishPower BY AFFILIATE TO UTILITY -SERVICES	N/A BY UTILITY TO AFFILIATE -SERVICES
Labor	116120		
Labor	210720	3,499,630.72	
Misc. Other Expenses	116120		327,445.94
Sub-total		3,499,630.72	327,445.94

Grand Summary	BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	3,642,929.07	247,102.06
Semi Tractor	0.00	0.00
Management Fee	0.00	184,626.47
Facilities Services	0.00	79,063.95
IT Allocations	0.00	96,401.40
Other Salary OH Assessments	0.00	1,104.07
SERP Assessments	0.00	21,425.26
LTD Assessments	0.00	2,000.77
Vehicle Lease Assessments	0.00	1,230.00
IT Services Allocations	0.00	111,300.00
Shared Services Chargebacks	0.00	14,709.42
Benefits	19,488.99	5,554.28
Fuel Purchased/Sold	48,928,106.04	0.00
Incentive Assessments	127,164.30	0.00
Benefits, Mgmt Fee, & Misc. Billings	0.00	2,818,542.00
Royalty Billings	0.00	0.00
Misc. Other Expenses	0.00	347,585.25
Total	52,717,688.40	3,930,644.93

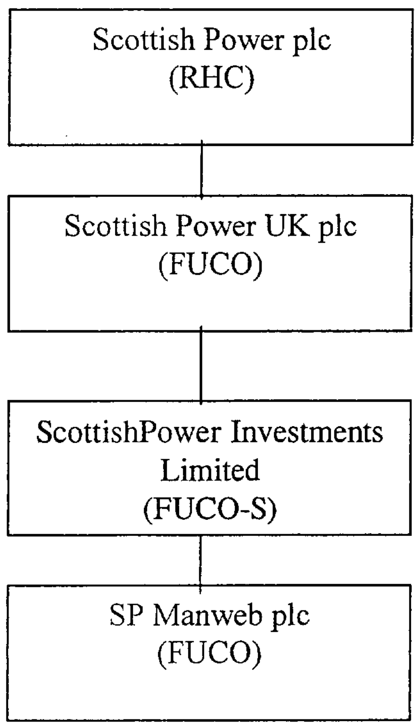
Affiliated Services Detail
For the Fiscal Year 2002

Components	SAP Acct	PacifiCorp Group Holdings BY AFFILIATE TO UTILITY -SERVICES	PacifiCorp Group Holdings BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		94,798.95
Facilities Services	690006		
IT Allocations	690007		2,025.90
LTD Assessments	690021		
IT Services Allocations	690025		44,100.00
Shared Services Chargebacks	690026		2,940.00
Benefits	699005		
Sub-total		0.00	143,864.85

Affiliated Services Detail
For the Fiscal Year 2002

Components	SAP Acct	PacifiCorp Group Holdings BY AFFILIATE TO UTILITY -SERVICES	BY UTILITY TO AFFILIATE -SERVICES
Labor	699000		12,467.06
Facilities Services	690006		
IT Allocations	690007		675.30
LTD Assessments	690021		
IT Services Allocations	690025		14,700.00
Shared Services Chargebacks	690026		2,205.00
Benefits	690005		
Sub-total		0.00	30,047.36

Attachment 4
Part II Organization chart showing relationship of each EWG and FUCO to other system companies.



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STATEMENTS OF CONSOLIDATED INCOME (LOSS)

(Millions of dollars)	2002	Years Ended March 31, 2001	2000
Revenues	$4,259.2	$5,056.7	$3,986.9
Operating expenses			
Purchased power	2,038.8	2,636.0	1,217.8
Fuel	490.9	491.0	512.3
Other operations and maintenance	562.8	705.2	726.0
Depreciation and amortization	403.0	429.0	441.3
Administrative and general	250.6	200.8	283.0
Taxes, other than income taxes	90.8	100.3	101.4
Unrealized gain on SFAS No. 133 - derivative instruments	(182.8)	-	-
Total	3,654.1	4,562.3	3,281.8
Other operating income	(32.4)	(30.6)	-
(Gain) loss on sale of Australian Electric Operations	(27.4)	184.2	-
Income from operations	664.9	340.8	705.1
Interest expense and other (income) expense			
Interest expense	227.7	290.4	341.4
Interest income	(23.6)	(31.6)	(17.1)
Interest capitalized	(6.9)	(12.9)	(20.2)
Losses from equity investments	-	1.4	2.6
Merger costs	-	9.3	195.5
Minority interest and other	(1.8)	(8.0)	(13.7)
Total	195.4	248.6	488.5
Income from continuing operations before income taxes and cumulative effect of accounting change	469.5	92.2	216.6
Income tax expense	176.1	180.4	134.0
Income (loss) from continuing operations before cumulative effect of accounting change	293.4	(88.2)	82.6
Discontinued operations (less applicable income tax expense: $36.4/2002 and $0.7/2000)	146.7	-	1.1
Income (loss) before cumulative effect of accounting change	440.1	(88.2)	83.7
Cumulative effect of accounting change (less applicable income tax benefit: $69.0/2002)	(112.8)	-	-
Net income (loss)	327.3	(88.2)	83.7
Preferred Dividend Requirement	(12.7)	(17.9)	(18.9)
Earnings (loss) on Common Stock	$ 314.6	$ (106.1)	$ 64.8

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENTS OF CONSOLIDATED CASH FLOWS

(Millions of dollars)	2002	2001	2000
		Years Ended March 31,	
Cash flows from operating activities			
Net income (loss)	$ 327.3	$ (88.2)	$ 83.7
Adjustments to reconcile net income (loss) to net cash provided by continuing operations			
Gain on disposal of discontinued operations	(146.7)	-	(1.1)
Cumulative effect of accounting change	112.8	-	-
Unrealized gain on SFAS No. 133	(182.8)	-	-
Loss (gain) on available for sale securities	7.6	(3.9)	(3.2)
Depreciation and amortization	403.0	429.0	456.3
Deferred income taxes and investment tax credits - net	60.9	(26.4)	136.7
Interest capitalized - equity funds	-	(4.4)	(11.2)
(Gain) loss on sale of subsidiary and assets	(52.6)	189.2	(1.0)
Utah rate order	-	-	(40.3)
Regulatory asset establishment - net	(21.0)	(35.1)	-
Deferred net power costs	(189.9)	(137.5)	-
Accrued Merger liabilities	(0.1)	(5.9)	71.0
Other	14.5	(44.8)	43.3
Accounts receivable and prepayments	165.2	(161.8)	(40.9)
Inventories	7.0	(9.3)	3.9
Accounts payable and accrued liabilities	(162.6)	543.8	66.3
Net cash provided by continuing operations	342.6	644.7	763.5
Net cash used in discontinued operations	-	-	(8.1)
Net cash provided by operating activities	342.6	644.7	755.4
Cash flows from investing activities			
Construction	(505.3)	(485.7)	(574.0)
Investments in and advances to affiliated companies - net	(130.8)	(5.3)	(2.6)
Advances to ScottishPower	(627.4)	(396.0)	-
Proceeds from ScottishPower note receivable	400.0	40.0	-
Proceeds from finance note repayment	189.9	-	-
Proceeds from sales of assets	83.2	1,010.0	169.3
Proceeds from sales of finance assets and principal payments	36.0	48.5	47.8
Proceeds from available for sale securities	120.9	119.9	125.9
Purchases of available for sale securities	(152.0)	(114.5)	(130.4)
Other	17.1	14.9	10.3
Net cash (used in) provided by investing activities	(568.4)	231.8	(353.7)
Cash flows from financing activities			
Changes in short-term debt	(64.0)	131.5	(88.1)
Proceeds from long-term debt, net	791.1	1,114.0	1,812.0
Dividends paid	(310.3)	(347.7)	(269.5)
Repayments of long-term debt	(59.0)	(1,787.0)	(2,099.0)
Redemptions of preferred stock	(100.0)	-	(26.1)
Other	(13.5)	(2.1)	7.0
Net cash provided by (used in) financing activities	244.3	(891.3)	(663.7)
Increase (decrease) in cash and cash equivalents	18.5	(14.8)	(262.0)
Cash and cash equivalents at beginning of period	139.4	154.2	416.2
Cash and cash equivalents at end of period	$ 157.9	$ 139.4	$ 154.2

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS

ASSETS

(Millions of dollars)	March 31, 2002	2001
Current assets		
Cash and cash equivalents	$ 157.9	$ 139.4
Accounts receivable less allowance for doubtful accounts: $34.8/2002 and $27.6/2001	376.1	567.0
Inventories at average cost	153.4	160.4
ScottishPower receivables	0.5	370.4
Accounts and notes receivable - affiliated entities	3.5	73.5
Other	17.5	46.7
Total current assets	708.9	1,357.4
Property, plant and equipment		
Domestic Electric Operations		
Production	4,861.7	4,827.5
Transmission	2,250.7	2,183.6
Distribution	3,773.8	3,630.3
Other	1,848.3	1,768.8
Construction work in progress	364.4	268.7
Total Domestic Electric Operations	13,098.9	12,678.9
Other Operations	-	33.5
Accumulated depreciation and amortization	(5,129.4)	(4,789.5)
Total property, plant and equipment - net	7,969.5	7,922.9
Other assets		
Regulatory assets	1,158.3	1,081.8
SFAS No. 133 regulatory asset	468.4	-
Finance note receivable	-	189.9
Finance assets - net	-	278.3
Deferred charges and other	366.2	303.5
Total other assets	1,992.9	1,853.5
Total assets	$10,671.3	$11,133.8

The accompanying notes are an integral part of these consolidated financial statements.

CONSOLIDATED BALANCE SHEETS, continued

LIABILITIES, REDEEMABLE PREFERRED STOCK AND SHAREHOLDER'S EQUITY

(Millions of dollars)	March 31, 2002	2001
Current liabilities		
Long-term debt currently maturing	$ 144.5	$ 51.2
Notes payable and commercial paper	176.5	240.5
Accounts payable	384.5	609.9
ScottishPower payables	0.8	13.6
Accounts and notes payable - affiliated entities	1.0	5.1
Taxes payable	115.9	377.5
Interest payable	100.8	84.1
Dividends payable	2.3	61.9
SFAS No. 133 current liability	100.4	-
Other	138.9	157.4
Total current liabilities	1,165.6	1,601.2
Deferred credits		
Income taxes	1,434.8	1,645.0
Investment tax credits	99.3	107.2
Regulatory liabilities	219.7	256.0
SFAS No. 133 non-current liability	405.5	-
Other	443.7	645.4
Total deferred credits	2,603.0	2,653.6
Long-term debt	3,553.8	2,906.9
Commitments and contingencies (See Note 16)	-	-
Guaranteed preferred beneficial interests in Company's junior subordinated debentures	341.5	341.2
Preferred stock subject to mandatory redemption	74.2	175.0
Redeemable preferred stock	41.3	41.5
Common equity		
Common shareholder's capital	2,742.1	3,284.9
Retained earnings	173.1	128.6
Accumulated other comprehensive income (loss):		
Unrealized gain on available for sale securities, *net of tax of $0.6/2002 and $0.6/2001*	0.7	0.9
Unrealized loss on derivative financial instruments, net of tax of $(14.7)	(24.0)	-
Total common equity	2,891.9	3,414.4
Total liabilities, redeemable preferred stock and shareholder's equity	$10,671.3	$11,133.8

The accompanying notes are an integral part of these consolidated financial statements.

STATEMENTS OF CONSOLIDATED CHANGES IN COMMON SHAREHOLDER'S EQUITY

(Millions of dollars, Thousands of shares)

	Common Shareholder's Capital		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Comprehensive Income (Loss) For The Year
	Shares	Amount			
Balance at March 31, 1999	297,331	$3,284.3	$738.8	$(54.7)	
Comprehensive income					
Net income	-	-	83.7	-	$ 83.7
Adjustment to retained earnings for subsidiary's differing fiscal year end	-	-	(10.4)	-	(10.4)
Other comprehensive income					
Unrealized gain on available-for-sale securities, net of tax of $3.0	-	-	-	4.4	4.4
Foreign currency translation adjustment, net of tax of $14.3	-	-	-	23.1	23.1
Cash dividends declared					
Preferred stock	-	-	(17.9)	-	-
Common stock ($0.58 per share)	-	-	(172.0)	-	-
Stock options exercised	62	1.2	-	-	-
Forfeitures	(68)	(0.6)	-	-	-
Balance at March 31, 2000	297,325	3,284.9	622.2	(27.2)	$100.8
Comprehensive income (loss)					
Net loss	-	-	(88.2)	-	$(88.2)
Other comprehensive income (loss)					
Foreign currency translation adjustment, net of tax of $(31.0)	-	-	-	(48.0)	(48.0)
Realization of foreign exchange loss included in net income, net of tax of $55.6	-	-	-	85.7	85.7
Unrealized loss on available-for-sale securities, net of tax of $(5.9)	-	-	-	(9.6)	(9.6)
Cash dividends declared					
Preferred stock	-	-	(15.4)	-	-
Common stock ($1.31 per share)	-	-	(390.0)	-	-
Balance at March 31, 2001	297,325	3,284.9	128.6	0.9	$(60.1)
Comprehensive income (loss)					
Net income	-	-	327.3	-	$327.3
Other comprehensive income (loss)					
Unrealized loss on available-for-sale securities, net of tax of $-	-	-	-	(0.2)	(0.2)
Cumulative effect of accounting change, net of tax of $377.5	-	-	-	617.2	617.2
Loss on derivative financial instruments recognized in net income, net of tax of $(70.2)	-	-	-	(115.1)	(115.1)
Unrealized loss on derivative financial instruments, net of tax of $(321.8)	-	-	-	(526.1)	(526.1)
Cash dividends declared					
Preferred stock	-	-	(9.8)	-	-
Common stock ($0.81 per share)	-	-	(240.8)	-	-
Transfer of Holdings	-	(542.8)	(32.2)	-	-
Balance at March 31, 2002	297,325	$2,742.1	$ 173.1	$ (23.3)	$303.1

The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - Summary Of Significant Accounting Policies

Nature of operations - The Company (which includes PacifiCorp and its subsidiaries) is a United States electricity company operating in six western states. The Company conducts its retail electric utility business as Pacific Power and Utah Power and engages in power production and sales on a wholesale basis.

Basis of presentation - The consolidated financial statements of the Company include its integrated domestic electric utility operations and its wholly owned and majority-owned subsidiaries. Significant intercompany transactions and balances have been eliminated upon consolidation.

The Federal Energy Regulatory Commission ("FERC") and the state utility commissions approved the Company's applications to implement an internal corporate restructuring and on December 31, 2001, all of the PacifiCorp common stock held by NA General Partnership ("NAGP") was transferred to PacifiCorp Holdings, Inc. ("PHI"), a wholly owned subsidiary of NAGP. PacifiCorp transferred all of the capital stock of PacifiCorp Group Holdings Company ("Holdings"), a wholly owned subsidiary of PacifiCorp, to PHI in February 2002. This was a non-cash transaction that resulted in a net reduction in shareholder's equity of $575.0 million. Holdings includes the wholly owned subsidiary, PacifiCorp Financial Services, Inc. ("PFS"), a financial services business.

In March 2001, the Company transferred its interest in PacifiCorp Power Marketing ("PPM") and Pacific Klamath Energy ("PKE") to PHI, as further discussed in Note 14.

The Company completed the sales of its ownership of Powercor Australia Ltd. ("Powercor") on September 6, 2000 and its 19.9% interest in Hazelwood Power Partnership ("Hazelwood") on November 17, 2000, as further discussed in Note 14. Powercor and Hazelwood represented all of the Australian Electric Operations segment of the Company.

On November 29, 1999, the Company and ScottishPower plc ("ScottishPower") completed a merger under which the Company became an indirect subsidiary of ScottishPower (the "Merger"). As a result of the Merger, the Company became part of a public utility holding company group, and as such, the Company's operations are subject to the requirements and restrictions of the Public Utility Holding Company Act of 1935. As a result of regulatory requirements and the existence of debt instruments that are secured by the assets of the Company, the basis of assets and liabilities reported in the Company's financial statements has not been revised to reflect the acquisition of the Company by ScottishPower. The assets, liabilities and shareholder's equity continue to be presented at historical cost.

Change in fiscal year - In connection with the Merger, the Company's year-end changed from December 31 to March 31. The years ended March 31, 2002, 2001 and 2000 and quarterly periods within those years are referred to as 2002, 2001 and 2000, respectively. References to future years are to years ending March 31. Australian Electric Operation's year-end remained December 31 after the Merger. Consequently, the Company's statements of consolidated income and consolidated cash flows as of and for the year ended March 31, 2001 include Australian Electric Operation's financial statements for the period from January 1, 2000 to the respective dates of sale. In accordance with guidelines of the Securities and Exchange Commission (the "SEC"), twelve months of income and expense for Australian Electric Operations were included in the consolidated statement of income for 2000.

Use of estimates - The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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 financial statements. Actual results could differ from those estimates.

Regulation - Accounting for the domestic electric utility business conforms with accounting principles generally accepted in the United States of America as applied to regulated public utilities and as prescribed by agencies and the commissions of the various locations in which the domestic electric utility business operates. The Company prepares its financial statements as they relate to Domestic Electric Operations in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS No. 71") as further discussed in Note 3.

Foreign currency - The financial statements for foreign subsidiaries, which were sold in 2001, were prepared in currencies other than the United States dollar. The income statement amounts were translated at average exchange rates for the year, while the assets and liabilities were translated at year-end exchange rates. Translation adjustments were included in Accumulated other comprehensive income (loss), a separate component of Common equity. All gains and losses resulting from foreign currency transactions are included in the determination of net income.

Cash and cash equivalents - For the purposes of these financial statements, the Company considers all liquid investments with maturities of three months or less, at the time of acquisition, to be cash equivalents.

Allowance for doubtful accounts - The Company's estimate for its allowance for doubtful accounts relating to trade receivables is based on two methods. The amounts calculated from each of these methods are combined to determine the total amount reserved. First, the Company evaluates specific accounts where it has information that the customer may have an inability to meet its financial obligations. In these cases, the Company uses its judgment, based on the best available facts and circumstances and records a specific reserve for that customer against amounts due to reduce the receivable to the amount that is expected to be collected. These specific reserves are reevaluated and adjusted as additional information is received that impacts the amount reserved. Second, a general reserve is established for all customers based on a range of percentages applied to aging categories. These percentages are based on historical collection and write-off experience. The Company provided \$16.0 million, \$10.6 million and \$22.0 million for doubtful accounts in 2002, 2001 and 2000, respectively. Write-offs of uncollectible accounts were $8.8 million, $10.8 million and $19.0 million in 2002, 2001 and 2000, respectively.

Inventory valuation - Inventories are generally valued at the lower of average cost or market, and consisted of $59.9 million and $67.7 million of fuel, and $93.5 million and $92.7 million of material and supplies, at March 31, 2002 and 2001, respectively.

Property, plant and equipment - Property, plant and equipment are stated at original cost of contracted services, direct labor and materials, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable domestic electric utility properties retired, including the cost of removal, less salvage, is charged to accumulated depreciation. The costs of planned major maintenance activities are expensed as the costs are incurred. Other repair and maintenance costs for property, plant and equipment are also expensed as incurred.

Depreciation and amortization - At March 31, 2002, the average depreciable lives of property, plant and equipment by category for Domestic Electric Operations were: Production, 41 years; Transmission, 58 years; Distribution, 42 years and Other, 20 years.

Depreciation and amortization are generally computed by the straight-line method in one of the following two manners, either as prescribed by the Company's various regulatory jurisdictions for Domestic Electric Operations' regulated assets, or over the assets' estimated useful lives. Composite depreciation rates on utility plants (excluding amortization of capital leases) in the Domestic Electric and Australian Electric Operations were 3.1%, 3.1% and 3.2% of average depreciable assets in 2002, 2001 and 2000, respectively.

Asset impairments - Long-lived assets to be held and used by the Company are reviewed for impairment when events or circumstances indicate costs may not be recoverable. Such reviews are performed in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets ("SFAS No. 144") which the Company adopted February 1, 2002, effective as of April 1, 2001, as described under *New accounting standards* below. The impacts of regulation on cash flows are considered when determining impairment. Impairment losses on long-lived assets are recognized when book values exceed expected undiscounted future cash flows with the impairment measured on a discounted future cash flows basis.

Interest capitalized - Costs of debt and equity applicable to domestic electric utility properties are capitalized during construction. The composite capitalization rates were 3.6% for 2002, 7.3% for 2001 and 7.9% for 2000.

Derivatives - As discussed in Note 11, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, effective April 1, 2001. The statement requires that the Company recognize all derivatives, as defined in the statement, on the balance sheet at fair value. Derivatives, or any portion thereof, that are not an effective hedge, are adjusted to fair value through income. If a derivative qualifies as an effective hedge, changes in the fair value of the derivative are either offset against the change in fair value of the hedged asset, liability, or firm commitment recognized in earnings, or are recognized in Accumulated other comprehensive income (loss) until the hedged items are recognized in earnings.

Finance assets - As discussed in Note 14, the Company transferred all of its interests in PFS to PHI in February 2002 and therefore has no finance assets as of March 31, 2002. At March 31, 2001, Finance assets consisted of finance receivables, leveraged leases and operating leases and were not significant to the Company in terms of revenue or net income. The Company's leasing operations consisted principally of leveraged aircraft leases. Investments in finance assets were net of accumulated impairment charges and allowances for credit losses of $42.6 million at March 31, 2001. The Company provided zero, $7.2 million and $11.0 million for impairment charges and credit losses in 2002, 2001 and 2000, respectively. Write-offs for impairment charges and credit losses were $8.4 million, zero and $2.0 million in 2002, 2001 and 2000, respectively.

Deferred charges and other - Deferred charges and other are comprised primarily of funds held in trust for the final reclamation of a leased coal mining property, investments to fund environmental remediation, unamortized debt expense, long term customer loans and receivables, certain employee benefit plan assets, and net amounts for corporate owned life insurance.

The Company maintains a trust relating to final reclamation of a leased coal mining property. Amounts funded are based on estimated future reclamation costs and estimated future coal deliveries. In both 2002 and 2001, the Company reviewed funding requirements based on estimated future gains and interest earnings on trust assets and the projected future reclamation liability. The Company determined that no funding was required for both 2002 and 2001. Securities held in the reclamation trust fund are recorded at market value in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," as discussed in Note 10. Trust assets include debt and equity securities classified as available for sale. Securities available for sale are carried at fair value with net unrealized gains or losses excluded from income and reported as Accumulated other comprehensive income (loss). Realized gains or losses are determined on the specific identification method.

Income taxes - The Company uses the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax bases of assets and liabilities and their financial reporting amounts.

Prior to 1980, Domestic Electric Operations did not provide deferred taxes on many of the timing differences between book and tax depreciation. In prior years, these benefits were flowed through to the utility customer as prescribed by the Company's various regulatory jurisdictions. Deferred income tax liabilities and Regulatory assets have been established for those flow through tax benefits, as shown in Note 13.

Investment tax credits for regulated Domestic Electric Operations are deferred and amortized to income over periods prescribed by the Company's various regulatory jurisdictions.

Provisions for United States income taxes were made on the undistributed earnings of the Company's international businesses.

Stock based compensation - As permitted by SFAS No. 123, "Accounting for Stock Based Compensation," the Company has elected to follow Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB No. 25") and related interpretations in accounting for employee stock options issued to Company employees. Under APB No. 25, because the exercise price of employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recorded. Upon completion of the Merger, all options are issued in ScottishPower American Depository Shares ("ADS"), as discussed in Notes 2 and 17.

Revenue recognition - Readings of customers' electric usage meters are staggered throughout the month. The Company accrues estimated unbilled revenues for electric services, provided after the meter read date to the month-end, based upon the Company's total delivery.

New accounting standards - In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS No. 142"), which addresses financial accounting and reporting for acquired goodwill and other intangible assets and supersedes APB Opinion No. 17, "Intangible Assets" ("APB No. 17"). SFAS No. 142 specifically states that it does not change the accounting prescribed by SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The Company has no goodwill recorded on its books. Due to the regulatory treatment for the Company's intangible assets, which were all internally developed, the adoption of SFAS No. 142 will have no material effect on the financial position or results of operations. This statement is effective for the Company beginning April 1, 2002.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations" ("SFAS No. 143"). The statement requires the fair value of an asset retirement obligation to be recorded as a liability in the period in which the obligation was incurred. At the same time the liability is recorded, the costs of the asset retirement obligation will be recorded as an addition to the carrying amount of the related asset. Over time, the liability is accreted to its present value and the addition to the carrying amount of the asset is depreciated over the asset's useful life. Upon retirement of the asset, the Company will settle the retirement obligation against the recorded balance of the liability. Any difference in the final retirement obligation cost and the liability will result in either a gain or loss. The Company will adopt this statement on April 1, 2003. The Company is currently evaluating the impact of adopting this statement on its financial position and results of operations.

In August 2001, the FASB issued SFAS No. 144, which modifies and expands the financial accounting and reporting for the impairment or disposal of long-lived assets other than goodwill, which is specifically addressed by SFAS No. 142. The new statement supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of" ("SFAS No. 121"), but retains many of the fundamental recognition and measurement provisions of SFAS No. 121. The Company adopted SFAS No. 144 in February 2002, effective as of April 1, 2001. The adoption of SFAS No. 144 resulted in the Company not classifying Holdings as Discontinued Operations following the internal restructuring.

Reclassification - Certain amounts from prior years have been reclassified to conform with the 2002 method of presentation. These reclassifications had no effect on previously reported consolidated net income (loss).

NOTE 2 - ScottishPower Merger

On November 29, 1999, the Company and ScottishPower completed the Merger under which the Company became an indirect subsidiary of ScottishPower. The Company continues to operate under its current name, and its headquarters remain in Portland, Oregon. As a result of the Merger, the Company became part of a public utility holding company group and, as such, the Company's operations are subject to the requirements and restrictions of the Public Utility Holding Company Act of 1935 (the "PUHCA"). Under the PUHCA, the Company may pay dividends out of capital or unearned surplus only with SEC approval. Dividends from earned surplus are permitted without approval. In addition, the PUHCA places restrictions on transactions with affiliates.

Each share of the Company's common stock was converted tax-free into a right to receive 0.58 ADS (each ADS represents four ordinary shares) or 2.32 ordinary shares of ScottishPower. Cash was paid in lieu of fractional shares.

The following table shows where Merger costs have been recorded in the Company's financial results. No Merger costs were incurred in 2002.

Merger Costs	Pretax		After-tax	
	Years Ended March 31,		Years Ended March 31,	
(Millions of dollars)	2001	2000	2001	2000
Included in Domestic Electric operating expenses				
Employee related expenses (severance, retention, etc.)	$ -	$ 12.7	$ -	$ 7.9
Legal fees, contracted services and other expenses	-	3.3	-	2.0
Total Merger costs included in operating expenses	-	16.0	-	9.9
Included within Merger costs - Domestic Electric				
Employee related expenses	-	23.7	-	22.1
Merger credits	12.0	57.2	7.4	35.5
Stamp tax	(2.7)	77.8	(2.7)	77.8
Banking fees	-	19.4	-	19.4
Legal fees, contracted services and other expenses	-	12.4	-	12.4
Total included within Merger costs - Domestic Electric	9.3	190.5	4.7	167.2
Included within Merger costs - Other Operations	-	5.0	-	3.1
Total included within Merger costs	9.3	195.5	4.7	170.3
Total Merger costs	$ 9.3	$211.5	$ 4.7	$180.2

As a result of the Merger, the Company has implemented a transition plan (the "Transition Plan") with significant organizational and operational changes. The Company expects to reduce its workforce Company-wide by approximately 1,600 from 1998 levels over a five-year period ending in 2005, mainly through early retirement, voluntary severance and attrition. At March 31, 2002, the Company had reduced its workforce by approximately 750 due to the Transition Plan. The estimated early retirement and severance costs are being deferred and amortized over future periods, as ordered by the various utility commission accounting orders received by the Company. The Company recorded $158.6 million in Regulatory assets and $16.6 million in Deferred charges as a result of the accounting orders issued by state regulatory bodies for these estimated costs. Below is a summary of the accruals recorded and payments made during 2002 and 2001 with respect to the deferred costs described above.

(Millions of dollars)	Years Ended March 31, 2002 and 2001 Total	Retirement Benefits	Severance and Other
Accruals recorded	$175.2	$ 99.4	$ 75.8
Payments	(12.5)	-	(12.5)
Reclassifications to accrued pension costs	(81.8)	(81.8)	-
Reclassifications to accrued postretirement benefit costs	(17.6)	(17.6)	-
Balance at March 31, 2001	63.3	-	63.3
Payments	(11.6)	-	(11.6)
Change in estimate	(9.1)	-	(9.1)
Reclassifications to accrued severance costs	(11.8)	-	(11.8)
Reclassification to regulatory asset	(30.8)	-	(30.8)
Balance at March 31, 2002	$ -	$ -	$ -

During the year, management determined to modify the manner in which the remaining workforce reductions would be achieved over the Transition Plan period, resulting in a reduction in the estimated remaining severance costs of $9.1 million. As a result, management determined it was no longer appropriate to account for the remaining liability under Emerging Issues Task Force ("EITF") No. 94-3 "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)." Therefore, the remaining liability of $30.8 million has been reclassified on the balance sheet to offset the related Transition Plan regulatory assets referred to above. There is no income statement impact from the change in estimate or reclassification of the Transition Plan liability.

NOTE 3 - Accounting For The Effects Of Regulation

Regulated utilities have historically applied the provisions of SFAS No. 71, which is based on the premise that regulators will set rates that allow for the recovery of a utility's costs, including cost of capital. Accounting under SFAS No. 71 is appropriate as long as: rates are established by or subject to approval by independent, third-party regulators; rates are designed to recover the specific enterprise's cost-of-service; and in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be collected from customers. In applying SFAS No. 71, the Company must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with SFAS No. 71, Domestic Electric Operations capitalizes certain costs as regulatory assets in accordance with regulatory authority whereby those costs will be expensed and recovered in future periods.

The EITF of the FASB concluded in 1997 that SFAS No. 71 should be discontinued when detailed legislation or regulatory orders regarding competition are issued. Additionally, the EITF concluded that regulatory assets and liabilities applicable to businesses being deregulated should be written-off unless their recovery is provided for through future regulated cash flows. The Company continuously evaluates the appropriateness of applying SFAS No. 71 to each of its jurisdictions. At March 31, 2002, management concluded that SFAS No. 71 was appropriate for its Domestic Electric Operations. However, if efforts to deregulate progress, the Company may in the future be required to discontinue its application of SFAS No. 71 to all or a portion of its business.

The Company is subject to the jurisdiction of public utility regulatory authorities of each of the states in which it conducts retail electric operations as to prices, services, accounting, issuance of securities and other matters. The jurisdictions in which the Company operates are in various stages of evaluating deregulation. At present, the Company is subject to cost based rate making for its Domestic Electric Operations business. The Company is a "licensee" and a "public utility" as those terms are used in the Federal Power Act (the "FPA") and is, therefore, subject to regulation by the FERC as to accounting policies and practices, certain prices and other matters.

SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from the inclusion of that cost in allowable costs for ratemaking purposes. In addition, the rate action should permit recovery of the specific previously incurred cost rather than to provide for expected levels of similar future costs. The statement makes it clear that a company does not need absolute assurance prior to capitalizing a cost, only reasonable assurance.

In an effort to mitigate the temporary discrepancy between prices paid to purchase power and revenues received through regulated rates, the Company requested and received regulatory approval from the utility commissions in the states of Utah, Oregon, Wyoming and Idaho to capitalize for each state some or all of the net power costs that vary from costs included in determining retail rates. At March 31, 2002, the Company had a balance of $305.4 million of such capitalized costs supported by stipulated agreements reached in Utah, Oregon, and Idaho and an estimate of the probable outcome of the Wyoming rate case expected to be settled late in calendar 2002. The determination of the amount to be recovered is subject to final commission orders from each of these states. Differences between the amount allowed by the commissions and the amounts capitalized at March 31, 2002 will be recognized as either a charge or credit to income upon receiving final commission orders.

Deferred accounting treatment for the effects of SFAS No. 133 on the financial statements of the Company has been granted in all the states the Company serves. The regulatory orders direct the deferral, as a regulatory asset or liability, of the effects of fair valuing long-term contracts that are included in the Company's rates.

Regulatory assets include the following:

(Millions of dollars)	March 31, 2002	2001
Deferred taxes (a)	$ 574.2	$ 593.8
Transition Plan costs - retirement and severance (b)	78.6	141.5
Deferred net power costs (c)	305.4	137.5
Demand-side resource costs	49.3	66.4
Unamortized net loss on reacquired debt	39.7	45.2
Utah and Oregon asset writebacks (d)	40.2	35.1
Unrecovered Trojan Plant	16.8	18.7
SFAS No. 133 regulatory asset (e)	468.4	-
SB 1149 related costs (f)	22.6	6.5
Various other costs	31.5	37.1
Total	$1,626.7	$1,081.8

(a) Excludes $99.3 million and $107.2 million as of March 31, 2002 and 2001, respectively, of investment tax credits.

(b) Represents the unamortized amount of retirement and severance costs relating to the Transition Plan that the state commissions allowed to be deferred and amortized. The 2002 amount reflects the reclassification of $30.8 million of severance accruals for the Transition Plan.

(c) Represents the deferred net power costs that vary from costs included in determining retail rates in the states of Utah, Oregon, Wyoming and Idaho.

(d) A Utah Public Service Commission ("UPSC") order during 2001 allowed recovery of early retirement and pension costs, reclamation costs, and Year 2000 and other information system costs that had previously been written-off. A UPSC order during 2002 allowed recovery of an additional $21.0 million of mine reclamation, information system and transition costs that had previously been written-off.

(e) Represents the current and non-current mark-to-market derivative adjustments on long-term purchased power contracts per FAS 133.

(f) Represents the State of Oregon Senate Bill 1149 ("SB 1149") related transition and implementation costs allowed to be recovered by a systems benefit charge allotted to associated customers effective March 1, 2002.

Regulatory liabilities include the following:

(Millions of dollars)	March 31, 2002	2001
Deferred taxes	$ 40.5	$ 43.7
Centralia gain (a)	115.3	150.9
Merger credits	24.0	47.2
Utah rate refund	34.7	-
Various other costs	5.2	14.2
Total	$ 219.7	$ 256.0

(a) Represents the gain on the sale of the Centralia plant and mine that is being returned to customers as ordered by the state commissions in connection with approving the sale. The gain amounts claimed by the jurisdictions the Company serves exceeded the actual gain on the transaction by $13.9 million resulting in a loss on sale that was recorded in Other operating income in 2001. The Company is no longer required to return a portion of the gain relating to Utah customers as discussed in Deferred Net Power Costs below.

The Company evaluates the recovery of all regulatory assets annually. The evaluation includes the probability of recovery as well as changes in the regulatory environment. Because of the potential regulatory and/or legislative action in Utah, Oregon, Wyoming, Washington and Idaho, the Company may have regulatory asset write-offs and charges for impairment of long-lived assets in future periods. Impairment would be measured in accordance with the Company's asset impairment policy, as discussed in Note 1.

Depreciation Rate Increase

During 1998, the Company filed applications with the respective regulatory commissions in the states of Utah, Oregon, Wyoming and Washington to increase rates of depreciation based on a new depreciation study. All applications were approved in 2000. The increase in rates of depreciation is primarily due to revisions of the estimated costs of removal for steam production and distribution plants. For the period April 1, 2000 to March 31, 2002, the Utah and Wyoming commissions ordered a reversal of a portion of previously accrued depreciation. These reversals in total, for both states, amounted to approximately $14.0 million per year for 2001 and 2002. The Company is required to file new depreciation studies in October 2002 based on plant balances as of March 31, 2002.

Trail Mountain Mine Closure Costs

On February 7, 2001, the Company filed applications with the UPSC, the Oregon Public Utilities Commission ("OPUC"), the Wyoming Public Service Commission ("WPSC") and the Idaho Public Utilities Commission ("IPUC") requesting accounting orders to defer $27.1 million in unrecovered costs associated with its Trail Mountain coal mine. The Company ceased operations at the mine on March 7, 2001. The mine is located in Central Utah and supplied fuel to the Hunter Plant. In April 2001, the WPSC and the IPUC approved deferred accounting treatment of their state's share of the $27.1 million of non-recovered Trail Mountain Mine investment costs. Additional closure-related costs in the amount of $18.7 million were subsequently identified, and the total amount subject to possible deferral increased to approximately

$45.8 million. The Company filed in Utah and Oregon to include the additional costs in its deferral application and received approval to defer the full $45.8 million for accounting purposes. In addition, the parties in Oregon signed a stipulation calling for a permanent $1.1 million annual rate reduction in Oregon due to the removal of the Trail Mountain assets from rate base. The stipulation also provides for a $2.6 million annual surcharge for five years to recover Oregon's share of mine closure costs. This stipulation requires OPUC approval. On April 4, 2002, the UPSC approved deferral of Utah's share of the $45.8 million with a five-year amortization beginning April 1, 2001.

In April 2002, the Company established a regulatory asset for the full closure costs of the Trail Mountain mine with a five-year amortization period beginning April 2001. The resulting regulatory asset at April 30, 2002 was $36.4 million, net of amortization. The reestablishment of the regulatory asset increased accumulated depreciation to reverse the effects of the retirement of the mine and decreased coal inventory costs for the closure-related costs. Recovery of the Trail Mountain amortization in Oregon was approved on May 20, 2002. The Company recently filed for recovery in Wyoming as part of its general rate case and will seek recovery in the remaining states.

<u>Merger Credits</u>
As a result of the Merger, the Company was required to provide benefits to ratepayers through fixed reductions in rates, or "Merger Credits." The Company's total obligation for Merger Credits was $133.4 million through the period ending December 31, 2004. The Company recorded $12.0 million and $57.2 million as liabilities and current expenses in its financial statements for the years ended March 31, 2001 and 2000, respectively, as those amounts were not subject to potential offsets. In May 2002, the UPSC allowed the Company to offset $21.0 million of future Merger Credits against deferred net power costs and eliminated the obligation for future Merger Credits in Utah. The IPUC is also considering a stipulation agreement that will allow the Company to offset future Merger Credits against deferred net power costs in the amount of $2.3 million. These actions will increase monthly revenues by approximately $1.0 million until December 31, 2003. Through March 31, 2002, the Company had provided $48.8 million in Merger Credits and interest to its customers through reduced rates. If the IPUC approves the outstanding stipulation, future Merger Credits of $44.3 million will still be due to customers in Oregon and Washington with the possibility of offsetting $21.0 million of that amount.

<u>Concluded Regulatory Actions</u>
<u>Utah</u> - On January 12, 2001, the Company filed a request with the UPSC for an increase in electricity rates for its customers in Utah. This request encompassed normalized power costs based on a test year of the twelve months ended September 30, 2000 and did not include those power cost variances associated with the Hunter No. 1 outage. The request would have increased prices by approximately 19.1% overall, or $142.0 million. On July 12, 2001, the Company agreed to reduce its request to an increase of $118.0 million. Concurrent with the initial filing, the Company filed a separate emergency petition for interim relief. On February 2, 2001, the UPSC granted an interim rate increase of $70.0 million, effective February 2, 2001. The $70.0 million interim rate increase was subject to refund if the final rate order did not

provide for at least that level of recovery. On September 10, 2001, in its final order, the UPSC granted the Company a $40.5 million revenue increase. This decision set new revenues about 5.1% higher than previous levels and allowed the Company to receive an additional $40.5 million in revenues during 2002. The rate increase was $29.5 million lower annually than the $70.0 million interim rate increase granted in February 2001. On November 2, 2001, the UPSC issued an order allowing the Company to retain temporarily the excess of the $70.0 million interim rate increase over the ordered $40.5 million revenue increase. The UPSC also allowed the Company to continue collecting the $29.5 million of revenue, subject to refund, as an offset to replacement power costs relating to the Hunter No. 1 outage. At March 31, 2002, the Company had collected $34.7 million of revenues subject to refund that were recorded as a regulatory liability. On May 1, 2002, the UPSC issued an order allowing the Company to apply the $34.7 million of previously collected revenues against the regulatory assets for deferred net power costs.

Oregon - On June 26, 2001, the Company received approval from the OPUC for an overall price increase of 1.0%, or $7.6 million, through an annual adjustment as part of the Alternative Form of Regulation ("AFOR") process previously authorized in Oregon. The new rates took effect July 1, 2001 and will run until the Company recovers all under-earnings relating to the AFOR. The Company received approximately $5.7 million in additional revenues in 2002 relating to this increase, which is expected to terminate in June 2002.

On November 1, 2000, the Company filed the unbundling generation, transmission and distribution cost information required under SB 1149 rules. See Deregulation below for further information on SB 1149. On September 7, 2001, the OPUC granted a rate increase in the amount of $64.4 million, effective September 10, 2001. This increase added approximately $37.7 million of revenues in 2002.

On January 17, 2002, the Company requested approval to begin recovering in rates the amortization of approximately $12.9 million of SB 1149 implementation costs, which were deferred between April and December 2001. At its public meeting on March 5, 2002, the OPUC granted this request effective March 6, 2002. This approval increases annual revenues by approximately $2.6 million, or 0.3%, overall. The OPUC had already ordered recovery of the approximately $5.4 million in SB 1149 costs incurred prior to March 31, 2001. In both cases, the deferred costs will be recovered over a five-year period. The Company is now recovering approximately $3.7 million annually of the SB 1149 costs, including $0.5 million in 2002.

In Oregon, the final order in the rate case that concluded in September 2001 required the Company to file the results of a new hourly net power cost model to replace the net power cost model currently used in setting rates. The Company filed this material in a power cost rate case on December 31, 2001 and requested a $34.3 million annual rate increase. The Company also filed for a permanent power cost adjustment mechanism. The Company filed a stipulation with all parties on March 29, 2002. The stipulation would result in an increase of $18.7 million for power cost recovery, in effect for one year. The Company would also agree to withdraw its request for a permanent power cost adjustment mechanism. The Company may renew this request after January 2003. The stipulation also includes the following major components: (i) a rate increase of $2.6 million for five years to reflect the recovery of additional Trail Mountain mine closure costs; (ii) offsetting reductions totaling $2.5 million in base rates ($0.7 million cut from net power costs, $0.7 million rate reduction due to the sale of the Company's Hermiston service territory and $1.1 million from the Trail Mountain closure); (iii) a rate decrease of $3.4 million in effect for one year reflecting the refund to customers of 95% of the gain relating to the Hermiston service territory sale; (iv) an additional decrease in base power costs of $1.2 million, which would be added back to power costs if the West Valley City, Utah affiliated interest application is approved (i.e., the Company could increase base rates by $1.2 million). An order approving the stipulation agreement was issued on May 20, 2002, increasing rates for one year by $15.4 million.

Wyoming - On July 9, 2001, the Company received an order from the WPSC approving the all-party stipulation that settled all issues in the Wyoming rate case filed on December 18, 2000. This order resulted in increased annual revenues of $8.9 million, effective August 1, 2001. Approximately $5.9 million in additional revenues were received in 2002.

Rate Increases Submitted for Regulatory Approval

California - On March 16, 2001, the Company filed an interim rate relief request with the California Public Utilities Commission ("CPUC") as Phase I in an effort to seek an increase in electricity rates for its customers in California. If approved by the CPUC, Phase I would increase rates about 13.8% overall, or $7.4 million. In addition, the Company has moved forward with its Phase II filing of a General Rate Case ("GRC") to increase rates to compensatory levels. The GRC request submitted on December 21, 2001, if approved by the CPUC, would raise customer rates 29.4% overall or $16.0 million annually, with an authorized return on equity of 11.5%. The annual amount requested would incorporate the Phase I interim amount. On December 26, 2001, the Office of Ratepayer Advocates ("ORA") filed a motion to dismiss or defer the Company's GRC request. The Company responded to ORA's motion on January 9, 2002. Following the expiration of the protest period, on February 25, 2002 the Company filed a motion for a pre-hearing conference to identify parties of record, establish a procedural schedule and address other issues.

Deferred Net Power Costs

On November 1, 2000, the Company filed applications in Utah, Oregon, Wyoming and Idaho seeking deferred accounting treatment for net power costs materially in excess of the power costs assumed in setting existing retail rates. The applications sought to defer these power cost variances beginning November 1, 2000. As discussed below, the Company received authorization to defer some power costs in excess of those included in retail rates in all the states where requests were made. At March 31, 2002, the Company had a regulatory asset of $305.4 million, including carrying costs, for total deferred power costs.

Utah - In Utah, pursuant to the UPSC's approval of deferred accounting treatment for replacement power costs resulting from the Hunter No. 1 outage, the Company filed on August 23, 2001 seeking permission to recover $103.5 million in replacement power costs over a 12-month period. On

November 2, 2001, the UPSC allowed the Company to apply over-collections from the general rate case toward Hunter No. 1 replacement power costs on an interim basis, subject to refund. The amount of the interim relief was approximately $29.5 million annually. As of March 31, 2002, $34.7 million had been collected toward Hunter No. 1 replacement costs.

Also in Utah, on September 21, 2001, the Company filed for permission to defer $109.0 million of excess net power costs above the level adopted in the Company's rate order of September 10, 2001. These costs were incurred during the period May 9, 2001 through September 30, 2001. A hearing relating to the deferral was held on December 7, 2001. On November 13, 2001, the Company also filed an application with the UPSC to recover, through a surcharge, the excess net purchased power costs incurred during the period May 9, 2001 through September 30, 2001. These filings are alternative approaches to recovery of effectively the same $109.0 million of costs that are not yet deferred. They are alternatives to each other and are not additive.

On May 1, 2002, the UPSC issued an order approving a stipulation agreement regarding recovery of deferred and non-deferred net power costs in Utah. The order allows the Company to continue collecting a $29.5 million annual surcharge until March 31, 2004 and to apply $34.7 million of revenue already collected subject to refund against deferred net power costs. The order allows the Company to offset deferred net power costs against a regulatory liability of $27.0 million for amounts to be returned to customers relating to the gain from the 2001 sale of the Centralia, Washington power plant. The Company will also realize $21.0 million by elimination of future Merger Credits. These regulatory liability offsets will reduce the regulatory asset for deferred net power costs. Monthly revenues will increase approximately $1.0 million until December 31, 2003 due to the termination of Merger Credit revenue reductions. The Company will record additional deferred net power costs of $37.9 million, withdraw its request to defer $109.0 million of excess net power costs and commit not to file a general rate case that would take effect prior to January 1, 2004, with certain exceptions. These actions should allow the Company to recover a total of $147.0 million of deferred and non-deferred net power costs in Utah.

Oregon - The Oregon deferred accounting filing encompassed all power costs that vary from the level in Oregon rates during the period from November 1, 2000 through September 9, 2001, including costs to replace lost generation resulting from the Hunter No. 1 outage. On January 18, 2001, the Company requested a 3.0%, or $23.0 million, annual rate increase effective February 1, 2001, to provide partial recovery of post-October 31, 2000 power cost variances attributable to Oregon over an amortization period. This 3.0% rate increase was the maximum allowed on an annual basis for the recovery of deferred costs under the Oregon statutes. On January 23, 2001, the OPUC authorized deferred accounting for power costs of $23.0 million. On February 20, 2001, the OPUC authorized the 3.0% rate increase effective February 21, 2001, subject to refund, pending the outcome of a separate phase of the proceeding to examine the prudence of these expenditures. The Company received $21.6 million in revenues as a result of this OPUC action. The OPUC has approved the Company's request to continue amortization at the 3.0% rate pending resolution of the prudence review, which is expected to be completed in June 2002.

The Company has appealed two OPUC orders, which establish the mechanism to determine the amount of power costs to defer, to the Marion County, Oregon, Circuit Court in separate complaints filed on October 1, 2001. The appeals have been consolidated. Oral arguments were held on May 9, 2002 and a ruling is expected in June 2002.

The Company filed with the OPUC on September 21, 2001 to increase the level of recovery of excess net power costs incurred to serve Oregon customers from the current 3.0% amortization level, or $23.0 million awarded in February 2001, to 6.0%. On October 22, 2001, the OPUC suspended the Company's request pending the outcome of the prudence phase of the proceeding. Upon completion of the prudence review, the Company will renew its request to increase the amortization level to 6.0%.

In December 2001, the Company and the OPUC staff reached a stipulation in the prudence phase of its deferred net power cost. The stipulation provides that proceeding, the Company would be permitted to recover 85.0% of the deferred net power costs in Oregon, or about $131.0 million plus carrying charges. The stipulation allows the Company to seek a higher level of recovery in the event the Company's appeal of the Commission's order limiting deferrals is successful. On May 20, 2002, the OPUC approved a one-year $15.4 million overall rate increase effective June 1, 2002 for the Company's Oregon customers to cover increases in power costs.

On September 7, 2001, the OPUC endorsed an agreement on deferral of net power costs after September 2001. The agreement specifies that until May 2002, the Company will defer the difference between 83.0% of actual net power costs and the new Oregon baseline power cost in tariffs. In December 2001, the parties to the original stipulation agreed to extend this mechanism until June 2002.

Wyoming - In Wyoming, on November 1, 2000, the Company filed for deferred accounting treatment of net power costs that vary from costs included in determining retail rates. The Company proposed to recover $47.0 million of deferred net power costs, incurred through June 2001, over a 12-month period. On November 20, 2001, following an order by the WPSC dismissing the majority of the Company's case based on a procedural issue, the Company requested authority to withdraw its excess power cost recovery filing without prejudice. On November 26, 2001, the WPSC granted the Company's motion. On May 7, 2002, the Company filed a Wyoming general rate case that includes a consolidation of all excess net power costs, including those for which recovery was being sought in the withdrawn proceeding, totaling $91.0 million.

Idaho - On January 7, 2002, the Company filed a request with the IPUC to recover $38 million of deferred net power costs through a temporary 24-month surcharge on customer bills and to implement a new credit to pass through Residential Exchange Program benefits from the two Bonneville Power Administration ("BPA") settlement agreements described above. The credit would not affect Company earnings. In addition, the Company requested an adjustment of individual rate classes to more closely reflect the actual cost-of-service and proposed a rate mitigation policy to ensure that no customer class would receive a rate increase during the period in which the proposed surcharge is in effect. Parties to the proceeding agreed to a stipulation that would allow recovery of $25.0 million of the deferred net power costs. This recovery would be achieved through a $22.7 million power cost surcharge plus the termination of future Merger Credits in the amount of $2.3 million. The IPUC conducted hearings beginning on May 7, 2002 to consider the stipulation.

Washington - On April 5, 2000, the Company filed a petition with the Washington Utilities and Transportation Commission ("WUTC") seeking authority to begin deferring excess net power costs as of June 1, 2002 for later recovery in rates, either through a power cost adjustment mechanism or a limited rate adjustment. Under the rate plan approved by the WUTC in August 2000 at the conclusion of the Company's last general rate case in Washington, there are limitations on the Company's ability to raise general rates prior to 2006. On May 10, 2002, the other parties to the rate plan filed a motion with the WUTC seeking to reopen the Company's 2000 general rate case and consolidate it with the Company's request for deferred accounting. A ruling on this motion by the WUTC is expected in early June 2002.

NOTE 4 - Discontinued Operations

The Company recognized $146.7 million of income during the first quarter of 2002 as a result of collecting a contingent note receivable relating to the discontinued operations of its former mining and resource development business, NERCO, Inc. ("NERCO"), which was sold in 1993. This note from the buyer was recorded at the date of the NERCO sale along with a corresponding deferred gain. Payments on this note were contingent upon the buyer receiving payment under a coal supply contract. The Company recognized this gain on a cost recovery basis as payments were received from the buyer. In June 2001, the Company received $189.9 million, which was full payment of the remaining balance of the note and recognized the remaining balance of the deferred gain. Deferred tax expense of $36.4 million was recognized on the gain in June 2001.

In October 1998, the Company decided to exit its energy trading business by offering for sale TPC Corporation ("TPC"), and ceasing PPM's electricity trading operations conducted in the eastern United States. PPM's activities in the eastern United States have been discontinued and all the related forward electricity trading has been closed. On April 1, 1999, Holdings sold TPC to NIPSCO Industries, Inc. for $150.3 million. Exiting these energy-trading activities resulted in a net after-tax gain of $1.1 million in the first quarter of 2000.

At March 31, 2001, Holdings had $8.0 million of current liabilities in Other relating to discontinued operations.

NOTE 5 - Related Party Transactions

There are no loans or advances between PacifiCorp and ScottishPower or PHI. Any such transactions would require state regulatory and SEC approval.

The tables below detail the Company's related party transactions and balances.

	March 31,	
(Millions of dollars)	2002	2001
Amounts due from affiliated companies		

ScottishPower		
Note receivable (a)	$ -	$370.0
Interest receivable (a)	-	0.1
Accounts receivable (b)	0.5	0.3
	$ 0.5	$370.4
PHI and its other subsidiaries (c)		
Notes receivable	$ -	$ 72.1
Accounts receivable	3.5	1.4
	$ 3.5	$ 73.5
Amounts due to affiliated companies		
ScottishPower payables (d)	$ 0.8	$ 13.6
PHI and its other subsidiaries (c)		
Accounts payable	$ -	$ 5.1
Notes payable	1.0	-
	$ 1.0	$ 5.1
Dividends payable		
ScottishPower	$ -	$ 57.8

	Years Ended March 31,		
a) (Millions of dollars)	2002	2001	2000
Revenues from affiliated companies			
PHI and its other subsidiaries (e)	$ 6.0	$ -	$ -
Expenses incurred from affiliated companies			
ScottishPower (d)	$16.5	$ 8.8	$ 4.7
Expenses recharged to affiliated companies			
ScottishPower (b)	$ 5.8	$ 0.3	$ -
Interest - net from affiliated companies			
ScottishPower (a)			
Interest income	$ 9.5	$14.0	$ -
PHI and its other subsidiaries (c)			
Interest income	$ 6.7	$ -	$ -
Interest expense	(0.1)	-	-
	$ 6.6	$ -	$ -

(a) Holdings, while a subsidiary of the Company, had a note receivable, interest receivable and related interest income from a directly owned subsidiary of ScottishPower.

(b) The Company recharges, to ScottishPower, payroll costs and related benefits of employees working for ScottishPower.

(c) Amounts shown are related to activity of Holdings, while a subsidiary of the Company, with PHI and its subsidiaries. PHI is a non-operating, U.S. holding company that was incorporated in December 2000. PHI is also an indirect wholly owned subsidiary of ScottishPower and became the Company's parent as of December 31, 2001. PHI also owns two energy companies that were owned by the Company until March 29, 2001.

(d) These expenses and liabilities primarily represent payroll costs and related benefits of ScottishPower employees in management positions with the Company or working for the Company on its Transition Plan.

(e) These revenues primarily represent wheeling revenues received from PPM.

Interest rates on related party borrowings approximate lender's cost of capital and are reset at 30-day intervals. The applicable rate at March 31, 2002 was 1.9% and at March 31, 2001 ranged from 5.08% to 5.23%. As noted in the above table, amounts due from affiliated companies in the prior year included the $370.0 million note due to Holdings from ScottishPower. As noted in Note 1, PacifiCorp transferred ownership of Holdings to PHI in February 2002. As Holdings is no longer a subsidiary of PacifiCorp, the ScottishPower note is no longer included in its results. As this note made up the majority of last year's affiliated company receivable balance, it was the main factor affecting average interest rates on related party borrowings. Along with the elimination of that receivable, declining interest rates in the current year contributed to the lower interest rate as of March 31, 2002.

In May 2002, PacifiCorp entered into a fifteen year operating lease on a power generation facility with PPM. PacifiCorp, at its sole option, may terminate the lease after three and six years. The facility is located in Utah, and is being constructed by West Valley Leasing Company, a wholly owned subsidiary of PPM. The facility will ultimately consist of five generation units each rated at 40 MW. Scheduled lease payments are $3.0 million annually per unit. Two of these units were operational May 1, 2002; two additional units are expected to be operational no later than June 1, 2002; and the fifth unit is expected to be operational no later than August 1, 2002.

NOTE 6 - Short-Term Debt And Borrowing Arrangements

The Company's short-term debt and borrowing arrangements were as follows:

(Millions of dollars)	Balance	Average Interest Rate (a)
March 31, 2002	$176.5	2.2%
March 31, 2001	$240.5	5.7%

(a) Computed by dividing the total interest on principal amounts outstanding at the end of the period by the weighted daily principal amounts outstanding.

At March 31, 2002, commercial paper and bank line borrowings were supported by $880.0 million of revolving credit agreements, which expire in June 2002. The facilities contain a one-year term loan option. The Company has signed new $800.0 million credit agreements that become effective June 4, 2002.

NOTE 7 - Long-Term Debt

The Company's long-term debt was as follows:

(Millions of dollars)	March 31, 2002	2001
PacifiCorp		
First mortgage bonds		
Maturing through 2007/5.7%-9.0%	$1,002.0	$1,052.7
Maturing 2008 through 2012/6.4%-9.2%	1,078.1	578.1
Maturing 2013 through 2017/7.3%-8.8%	91.0	91.0
Maturing 2018 through 2022/8.3%-8.5%	30.7	30.7
Maturing 2023 through 2027/6.7%-8.6%	432.5	432.5
Maturing 2028 through 2032/7.7%	300.0	-
Guaranty of pollution control revenue bonds		
5.6%-5.7% due 2022 through 2024 (a)	71.2	71.2
Maturing 2031/6.2%	12.7	12.7
Variable rate due 2014 (a)(b)	40.7	40.7
Variable rate due 2025 (a)(b)	175.8	175.8
Variable rate due 2006 through 2031 (b)	438.0	438.0
Funds held by trustees	(2.0)	(2.1)
Capitalized lease obligations, maturing 2014 through 2022/10.4%-14.8%	27.6	27.2
Unamortized premium or discount	(5.0)	(2.8)
Total	3,693.3	2,945.7
Less current maturities	(143.9)	(50.3)
Total	3,549.4	2,895.4
Subsidiaries		
8.6% Note due 2005	5.0	5.5
6.0%-6.1% Notes due through 2003 (c)	-	6.9
Total	5.0	12.4
Less current maturities	(0.6)	(0.9)
Total	4.4	11.5
Total	$3,553.8	$2,906.9

(a) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution control revenue bonds.

(b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

(c) PFS notes extinguished in 2002 due to the synthetic fuel operations sale.

First mortgage bonds of the Company may be issued in amounts limited by Domestic Electric Operations' property, earnings and other provisions of the mortgage indenture. Approximately $11.5 billion of the eligible assets (based on original cost) of PacifiCorp are subject to the lien of the mortgage. Approximately $1.5 billion of first mortgage bonds were redeemable at the Company's option at March 31, 2002 at redemption prices dependent upon U.S. Treasury yields. Approximately $654.5 million of pollution control revenue bonds were redeemable at the Company's option at par at March 31, 2002. Subsidiary notes are redeemable at the Company's option at face amount. The remaining long-term debt was not redeemable at the Company's option at March 31, 2002.

On November 21, 2001, the Company issued $500.0 million of its 6.9% Series of First Mortgage Bonds due November 15, 2011 and $300.0 million of its 7.7% Series of First Mortgage Bonds due November 15, 2031. The Company used the proceeds for general corporate purposes, including the repayment of commercial paper and short-term debt borrowed from Holdings. The Company has an effective shelf registration statement for up to $1.1 billion of long-term debt, of which $800.0 million has been authorized to be issued by the applicable regulatory commissions, subject to certain conditions. Any such issuance would be subject to market conditions.

The annual maturities of long-term debt, capitalized lease obligations and redeemable preferred stock outstanding are $148.2 million, $140.4 million, $243.5 million, $289.2 million and $242.5 million in 2003 through 2007, respectively.

The Company made interest payments, net of capitalized interest, of $246.7 million, $337.5 million and $402.4 million in 2002, 2001 and 2000, respectively. This includes interest on leveraged lease debt that is netted against revenue on leveraged leases.

NOTE 8 - Guaranteed Preferred Beneficial Interests In Company's Junior Subordinated Debentures

Wholly-owned subsidiary trusts of the Company (the "Trusts") have issued, in public offerings, redeemable preferred securities ("Preferred Securities") representing preferred undivided beneficial interests in the assets of the Trusts, with liquidation amounts of $25.0 per Preferred Security. The sole assets of the Trusts are Junior Subordinated Deferrable Interest Debentures of the Company that bear interest at the same rates as the Preferred Securities to which they relate, and certain rights under related guarantees by the Company.

Preferred Securities outstanding were as follows:

(Millions of dollars, Thousands of Preferred Securities)		II. MARCH 31,	
		III. 2002	IV. 2001
8,680	8.25% Cumulative Quarterly Income Preferred Securities, Series A, with Trust assets of $223.7 million (a)	$210.6	$210.4
5,400	7.70% Trust Preferred Securities, Series B, with Trust assets of $139.2 million (b)	130.9	130.8
Total		$341.5	$341.2

(a) Amount is net of unamortized issuance costs of $6.4 million and $6.6 million at March 31, 2002 and 2001, respectively.

(b) Amount is net of unamortized issuance costs of $4.1 million and $4.2 million at March 31, 2002 and 2001, respectively.

All of the 8.25% Cumulative Quarterly Income Preferred Securities, Series A, were redeemable at the Company's option at face amount at March 31, 2002.

NOTE 9 - Common and Preferred Stock

Common Stock - The Company has one class of common stock with no par value. A total of 750,000,000 shares were authorized and 297,324,604 were issued and outstanding at March 31, 2002 and 2001.

Common Dividend Restrictions - ScottishPower is the sole indirect shareholder of the Company's common stock. The Company is restricted from paying dividends or making other distributions to ScottishPower without prior OPUC approval to the extent such payment or distribution would reduce the Company's common stock equity below a specified percentage of its total capitalization. The percentage of total capitalization increases over time from 35.0% after December 31, 1999 to 40.0% after December 31, 2004. In addition, the Company must give the OPUC 30 days prior notice of any special cash dividend or any transfer involving more than five percent of PacifiCorp's retained earnings in a six-month period. The Company is also subject to maximum debt to total capitalization levels under various debt agreements.

Under the Public Utility Holding Company Act of 1935, the Company may pay dividends out of capital or unearned surplus only with SEC approval. Dividends from earned surplus are permitted without approval. The Company has received approval to pay dividends out of unearned surplus of the lesser of $900.0 million or the proceeds received from sales of non-utility assets. At March 31, 2002, $300.0 million was available for dividends out of unearned surplus.

Preferred Stock

(Thousands of shares)	
At December 31, 1998	3,160
Redemptions and repurchases	(995)
At March 31, 2001 and 2000	2,165
Redemptions and repurchases	(1,000)
At March 31, 2002	1,165

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon voluntary or involuntary liquidation, all preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Any premium paid on redemptions of preferred stock is capitalized, and recovery is sought through future rates. Dividends on all preferred stock are cumulative.

Preferred Stock Outstanding (Millions of dollars, Thousands of shares)	March 31, 2002		March 31, 2001	
Series	Shares	Amount	Shares	Amount
Subject to Mandatory Redemption				
No Par Serial Preferred,				
$100 stated value,				
16,000 Shares authorized				
$7.70	-	$ -	1,000	$100.0
7.48	750	74.2	750	75.0
	750	74.2	1,750	175.0
Not Subject to Mandatory Redemption				
Serial Preferred, $100 stated value,				
3,500 Shares authorized				
4.52%	2	0.2	2	0.2
4.56	85	8.4	85	8.5
4.72	70	6.9	70	7.0
5.00	42	4.2	42	4.2
5.40	66	6.6	66	6.6
6.00	6	0.6	6	0.6
7.00	18	1.8	18	1.8
5% Preferred, $100 stated value,				
127 Shares authorized	126	12.6	126	12.6
	415	41.3	415	41.5
Total	1,165	$115.5	2,165	$216.5

Mandatory redemption requirements at stated value plus accrued dividends on No Par Serial Preferred Stock are as follows: 37,500 shares of the $7.48 series are redeemable on each June 15 from 2002 through 2006, with all shares outstanding on June 15, 2007 redeemable on that date. If the Company is in default in its obligation to make any future redemptions on the $7.48 series, it may not pay cash dividends on common stock.

The Company had $2.3 million in preferred dividends declared but unpaid at March 31, 2002. The Company had $57.8 million and $4.1 million in common and preferred dividends, respectively, declared but unpaid at March 31, 2001.

NOTE 10 - Securities Available For Sale

The amortized cost and fair value of reclamation trust securities and other investments, which are classified as available for sale, were as follows:

(Millions of dollars)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
March 31, 2002				
Money market account	$ 2.7	$ -	$ -	$ 2.7
Mutual fund account	29.3	-	(0.5)	28.8
Debt securities	26.9	0.5	(0.2)	27.2
Equity securities	50.7	5.8	(3.4)	53.1
Total	$109.6	$ 6.3	$ (4.1)	$111.8
March 31, 2001				
Money market account	$ 2.7	$ -	$ -	$ 2.7
Debt securities	25.1	0.7	-	25.8
Equity securities	54.9	7.9	(6.1)	56.7
Total	$ 82.7	$ 8.6	$ (6.1)	$ 85.2

The quoted market price of securities at March 31, 2002, is used to estimate the securities' fair value.

The amortized cost and estimated fair value of debt securities at March 31, 2002 and 2001 by contractual maturities are shown below. Actual maturities may differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

	V. MARCH 31,			
	VI. 2002		VII. 2001	
(Millions of dollars)	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Debt securities				
Due in one year or less	$ -	$ -	$ 0.8	$ 0.9
Due after one year through five years	6.0	6.1	6.6	6.8
Due after five years through ten years	8.7	8.8	7.0	7.2
Due after ten years	12.2	12.3	10.7	10.9
Money market account	2.7	2.7	2.7	2.7
Mutual fund account	29.3	28.8	-	-
Equity securities	50.7	53.1	54.9	56.7
Total	$109.6	$111.8	$ 82.7	$ 85.2

Proceeds, gross gains and gross losses from realized sales of available-for-sale securities using the specific identification method were as follows for the years ended March 31, 2002, 2001 and 2000:

(Millions of dollars)	Years Ended March 31, 2002	2001	2000
Proceeds	$120.9	$119.9	$125.9
Gross gains	$ 4.5	$ 11.8	$ 8.2
Gross losses	(12.1)	(7.9)	(5.0)
Net (losses) gains	$ (7.6)	$ 3.9	$ 3.2

NOTE 11 - Derivative Instruments

On April 1, 2001, the Company adopted SFAS No. 133, as amended by SFAS No. 138 and numerous interpretations of the Derivatives Implementation Group ("DIG") that are approved by the FASB, collectively "SFAS No. 133." Under SFAS No. 133, derivative instruments are recorded on the Consolidated Balance Sheet as an asset or liability measured at estimated fair value, with changes in fair value recognized currently in earnings (in Purchased power and Fuel), unless specific hedge accounting criteria are met. As contracts settle, sales are recorded in Operating revenues, with purchases and futures recorded in Purchased power and Fuel on the Statements of Consolidated Income (Loss). A derivative financial instrument or other contract derives its value from another investment, a designated benchmark, or an underlying price.

The Company's primary business is to serve its retail customers. The Company's business is exposed to risks relating to, but not limited to, changes in certain commodity prices and counterparty performance. The Company enters into derivative instruments, including electricity, natural gas and coal forward, option and swap contracts, and weather contracts to manage its exposure to commodity price risk and thereby attempts to minimize variability in net power costs for customers. The majority of these contracts qualify for the normal purchase and normal sale exception under SFAS No. 133. The Company has policies and procedures to manage risks inherent in these activities and a Risk Management Committee to monitor compliance with the Company's risk management policies and procedures.

The Risk Management Committee has limited the types of commodity instruments the Company may trade to those related to electricity, natural gas and coal commodities and those instruments are to be used for hedging price fluctuations associated with the management of resources. Commodity instruments are not generally held by the Company for speculative trading purposes. The estimated fair value of trading instruments at March 31, 2002, was $1.1 million favorable to the Company.

The accounting treatment for the various classifications of derivative financial instruments under SFAS No. 133 is as follows:

Normal purchases and normal sales - The contracts that qualify as normal purchases and normal sales are excluded from the requirements of SFAS 133. The realized gains and losses on these contracts are reflected in the income statement at the contract settlement date.

Cash Flow Hedge - The unrealized gains and losses relating to these forward contracts are included in Accumulated other comprehensive income (loss), a component of shareholder's equity. As the forward contracts are settled, the realized gains and losses are recorded on the Statements of Consolidated Income (Loss) as a component of Operating revenues or Purchased power and the unrealized gains and losses are reversed from Accumulated other comprehensive income (loss).

Trading Activity - The unrealized gains and losses relating to these forward contracts are reflected in the Statements of Consolidated Income (Loss) as a component of Operating revenues. As the forward contracts are settled, the realized gains or losses are recorded and the unrealized gains and losses are reversed.

The Company has the following types of commodity transactions:

Coal, natural gas, and other fuel purchase contracts - The Company enters into long-term and short-term coal, natural gas, diesel, and other purchase contracts to provide adequate fuel resources to its electricity generation facilities. These contracts generally have limited optionality and require the Company to take physical delivery of the commodity. These contracts are generally determined to be normal purchases and normal sales contracts under SFAS No. 133.

Weather derivatives - To a limited degree, the Company has executed contracts to hedge changes in hydroelectric generation due to variation in precipitation, streamflow, or temperature. These contracts are not exchange traded and settlement is based on climatic or other physical variables. Therefore, on a periodic basis, the Company estimates and records a gain or loss in earnings corresponding to the total expected future cash flow from these contracts in accordance with EITF No. 99-2, "Accounting for Weather Derivatives." At March 31, 2002, amounts recorded for these contracts were $1.2 million.

Wholesale electricity purchase and sales contracts - The Company makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historic load and forward market and other economic information and experience. Based on these projections, the Company purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements and sells any surplus at the best available price. This process involves hedging transactions which include the purchase and sale of firm capacity and energy under long-term contracts, forward physical or financial contracts for the purchase and sale of a specified amount of capacity or energy at a specified price over a given period of time (typically for one month, three months or one year), and forward purchases and sales of transmission service.

Upon adoption of SFAS No. 133 on April 1, 2001, all wholesale contracts were examined and it was determined that some of the forward contracts for the purchase or sale of wholesale power were considered to be derivatives based on the accounting guidance at that time. The effects of changes in fair value of certain derivative instruments entered into to hedge the Company's future retail resource requirements are subject to regulation and, therefore, are deferred pursuant to SFAS No. 71. The Company requested and received deferred accounting orders for the effects of SFAS No. 133 as it relates to the change in fair value of long-term wholesale electricity contracts not meeting the definition of normal purchases and normal sales contracts. At the date of adopting SFAS No. 133, the Company recorded a net regulatory asset relating to the fair value of long-term wholesale contracts (which did not meet the definition of normal purchases and normal sales contracts) of $711.0 million. Short-term wholesale electricity purchase contracts not meeting the definition of normal purchases and normal sales contracts were designated as cash flow hedges to hedge the risk of changes in the cost of providing electricity to serve the Company's retail load. These hedges were fully effective. At the date of adopting SFAS No. 133, the Company recorded an unrealized after-tax gain of $617.2 million as a component of equity related to the fair value of short-term wholesale purchase contracts. Short-term wholesale electricity sales contracts not meeting the definition of normal purchases and normal sales contracts were marked to market through income, resulting in a $112.8 million after-tax loss on adoption of SFAS No. 133.

In June 2001, the DIG issued guidance which provided that certain forward power purchase or sales agreements, including capacity contracts, could be excluded from the requirements of SFAS No. 133 by expanding the normal purchases and normal sales exclusion. The Company implemented this new guidance, on a prospective basis, beginning July 1, 2001. As a result, substantially all of the Company's short-term wholesale electricity contracts were determined to meet the normal purchases and normal sales exclusion. No further market value changes were recognized for those excluded contracts and unrealized gains (losses) recorded in Other comprehensive income ("OCI") relating to the existing cash flow hedges as of July 1, 2001 are reversed prospectively when the related contracts are settled.

To mitigate exposure to credit risk, the Company has entered into master netting agreements with all of its significant trading counter parties. Unrealized gains and losses on contracts with parties under master netting agreements are presented net on the financial statements.

The following table summarizes the SFAS No. 133 adoption and activity for the year:

(millions)	Current Assets (Liability)	Regulatory Net Asset (Liability)	Deferred Tax Asset (Liability)	Income (Loss)	OCI Gain (Loss)
Adoption April 1, 2001	101.6	711.2	(308.5)	(112.8)	617.2
Settlements	60.2	(20.3)	(15.2)	139.7	(115.1)
Change in fair value	(667.7)	(222.5)	337.9	(26.2)	(526.1)
Balance March 31, 2002	(505.9)	468.4	14.2	0.7	(24.0)

Short-term contracts are valued based upon quoted market prices. Long-term contracts are valued by separating each contract into its component physical and financial swap and option legs. Swap legs are valued against the appropriate market curve. The option leg is valued using a modified Black-Scholes model approach. Each leg is modeled and valued separately using the appropriate forward market price curve. The forward market price curve is derived using daily market quotes form independent energy brokers. For contracts extending past 2006, the forward prices are derived using a fundamentals model (cost-to-build approach) that is updated as warranted to reflect changes in the market, at least quarterly.

As of March 31, 2002, the Company anticipated that approximately $38.6 million ($24.0 million after-tax) of the unrealized net losses on derivative instruments in Accumulated other comprehensive income (loss) will reverse during the subsequent twelve months as the underlying contracts are settled. A corresponding change to the SFAS No. 133 asset will be recorded with no net effect on earnings. As of March 31, 2002, contracts designated as cash flow hedges have contractual settlement dates through September 2002.

During 2001, the DIG issued guidance under Issue C16, "Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract" ("Issue C16"). The guidance disallows normal purchases and normal sales treatment for commodity contracts (other than power contracts) that contain volumetric variability or optionality. Issue C16 is effective April 1, 2002. As a result, these contracts will be required to be marked-to-market through earnings. The Company will be reviewing its contracts to determine which contracts, if any, will no longer qualify as normal purchase and normal sales contracts.

To date, the DIG has issued more than 100 interpretations to provide "guidance" in applying SFAS No. 133. As the DIG or the FASB continues to issue interpretations, the Company may change the conclusions that it has reached and, as a result, the accounting treatment and financial statement impact could change in the future.

NOTE 12 - Fair Value of Financial Instruments

	March 31, 2002		March 31, 2001	
(Millions of dollars)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (a)	$3,670.7	$3,763.5	$2,930.9	$3,024.8
Preferred Securities	341.5	338.1	341.2	333.7
Preferred stock subject to mandatory redemption	74.2	81.5	175.0	185.5

(a) Represents long-term debt and long-term debt classified as currently maturing, less capitalized lease obligations.

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. The fair value of the finance note receivable approximates its carrying value at March 31, 2001.

The fair value of the Company's long-term debt and redeemable preferred stock has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities. Current maturities of long-term debt were included. Preferred Securities were estimated using quoted market prices at March 31, 2002 and 2001.

NOTE 13 - Income Taxes

Upon its acquisition by ScottishPower, the Company became a member of a group that files its federal and state tax returns on a consolidated basis. Tax expense is calculated on a separate return basis. Amounts payable for federal and state taxes are remitted to the Company's parent.

The Company's combined federal and state effective income tax rate from continuing operations was 37.5% for 2002, 195.7% for 2001 and 61.9% for 2000.

The difference between taxes calculated as if the statutory federal tax rate of 35.0% was applied to income from continuing operations before income taxes and the recorded tax expense is reconciled as follows:

		Years Ended March 31,	
(Millions of dollars)	2002	2001	2000
Computed Federal Income Taxes	$164.3	$ 32.3	$ 75.8
Increase (Reduction) in Tax Resulting from:			
Depreciation differences	13.7	21.4	23.0
Depletion	(1.5)	(3.0)	(4.2)
Investment tax credits	(10.8)	(9.4)	(9.1)
Merger costs	-	(0.9)	41.7
Affordable housing and alternative fuel credits	-	-	(27.9)
Loss from sales of Australian operations (a)	(9.9)	74.3	-
Tax reserves	20.9	66.2	27.6
Income taxed at less than statutory rate	(4.6)	(4.0)	(3.1)
Corporate owned life insurance	(3.3)	(3.0)	(1.9)
Nontaxable income	(1.4)	(2.4)	(2.6)
All other	(4.8)	(2.8)	2.6
Total	(1.7)	136.4	46.1
Federal Income Tax	162.6	168.7	121.9
State Income Tax, Net of Federal Income Tax Benefit	13.5	11.7	12.1
Total Income Tax Expense	$176.1	$180.4	$134.0

(a) The Company did not have enough capital gains to offset the capital losses resulting from the sale of the Australian operations in 2001. Subsequently, an election was made to reattribute a portion of the losses to the group so that a benefit could be taken.

The provision for income taxes is summarized as follows:

(Millions of dollars)	2002	Years Ended March 31, 2001	2000
Current			
Federal	$104.1	$190.2	$(12.1)
State	11.1	16.6	9.4
Total	115.2	206.8	(2.7)
Deferred			
Federal	63.2	(18.4)	136.5
State	8.5	1.4	9.3
Total	71.7	(17.0)	145.8
Investment Tax Credits	(10.8)	(9.4)	(9.1)
Total Income Tax Expense	$176.1	$180.4	$134.0

The tax effects of significant items comprising the Company's net deferred tax liability were as follows:

(Millions of dollars)	March 31, 2002	2001
Deferred Tax Liabilities		
Property, plant and equipment	$ 965.4	$1,160.5
Regulatory assets	574.2	593.8
Other deferred liabilities	17.8	135.7
	1,557.4	1,890.0
Deferred Tax Assets		
Regulatory liabilities	(40.5)	(43.7)
Book reserves not currently deductible for tax	(43.8)	(71.2)
Pension accrual	(16.4)	(24.8)
Safe harbor lease	(13.2)	(10.3)
Other deferred assets	(8.7)	(95.0)
	(122.6)	(245.0)
Net Deferred Tax Liability	$1,434.8	$1,645.0

During the current year, the Company settled its litigation with the IRS for the 1989 and 1990 tax years. A liability for the full tax impact of this settlement had been previously established. The additional payment of tax and interest was fully offset by a tax payment posted with the IRS in 1999.

The Company has concluded its settlement discussions with the IRS Appeals Division for the 1991, 1992 and 1993 tax years. The tax impact for this settlement is approximately $10.3 million. The Company has established a liability for this amount and is awaiting final billing from the IRS for these years. The examination of the Company's 1994 through 1998 tax years is expected to be completed by June 2002. The IRS has not yet issued a Revenue Agent's Report for these years. The IRS has also notified the Company that it intends to start the examination of the 1999 and 2000 tax years beginning September 2002.

The Company made net income tax payments of $83.1 million for 2002 and in 2001 and 2000 received net income tax refunds of $63.9 million and $1.8 million, respectively.

NOTE 14 - Dispositions

On December 31, 2001, NAGP contributed all of the common stock of PacifiCorp to PHI. On February 4, 2002, PacifiCorp transferred all of the capital stock of Holdings to PHI. Accordingly, the results of operations and assets of Holdings are not included with those of PacifiCorp commencing February 4, 2002.

In October 2001, PFS sold its synthetic fuel operations. PFS received proceeds from the sale of $45.0 million and will receive quarterly royalty payments from the purchaser through October 2007. The sale resulted in a gain of approximately $11.3 million, pretax.

During the first quarter of 2002, the Company sold aircraft owned by subsidiaries of PFS. PFS received proceeds of approximately $36.0 million and recorded a $9.3 million pretax gain on the sale. These assets had previously been reported under Finance Assets - Net on the balance sheet.

In connection with an internal restructuring of the Company, the Company transferred its interest in two non-utility energy companies to an affiliated entity, PHI, in March 2001. The transfer price of $72.4 million was based on an estimate of market value and was financed through a loan from Holdings. The income and cash flow impacts from the two companies are included in the 2001 results, but the assets and liabilities associated with those businesses were removed from the consolidated balance sheet upon the transfer to PHI. No gain was recognized on the transfer. The difference between the transfer price and the book value was recorded as an adjustment to equity.

In 2001, Holdings completed the sale of its ownership of Powercor and its 19.9% interest in Hazelwood for approximately AUS $2.4 billion and approximately AUS $88.0 million, respectively. Powercor and Hazelwood represented all of the Australian Electric Operations segment of the Company. The Company recorded an after-tax loss on the sale of $197.7 million. In June 2001, upon resolution of a contingency under the provisions of the Powercor sale agreement, the Company received further proceeds due from the sale that resulted in income of $27.4 million in 2002.

The loss on sale of Australian Electric Operations for the year ended March 31, 2002 and 2001 is as follows:

(Millions of dollars)	(a) March 31, 2002 (c) Pretax	(d) After-Tax	(b) March 31, 2001 (e) Pretax	(f) After-Tax
Australian Electric Operations:				
Gain (loss) on sale	$27.4	$27.4	$(109.1)	$(109.1)(a)
Loss due to cumulative unfavorable changes in foreign exchange rate	-	-	(108.5)	(108.5)(a)
Total Australian Electric Operations	27.4	27.4	(217.6)	(217.6)
Other Operations:				
Loss on repayment of debt	-	-	(1.9)	(1.9)
Net gain on swap settlement	-	-	35.3	21.8
	-	-	33.4	19.9
Total gain (loss) on sale	$27.4	$27.4	$(184.2)	$(197.7)

(a) The Company did not have enough capital gains to offset this capital loss and does not anticipate any further tax benefit from this loss.

In October 2001, the Company and Nor-Cal Electric Authority ("Nor-Cal") reached an agreement in principle for the sale of the Company's California electric service territory. The parties have been working to complete the sale of these properties since 1999. In December 2000, the CPUC turned down a previous agreement between these parties. If a new definitive agreement is reached, it will be subject to approval by the CPUC, which is expected to take between six months and one year.

On May 4, 2000, the utility partners, including the Company, who owned the 1,340 Megawatt ("MW") coal-fired Centralia Power Plant sold the plant and the adjacent coal mine, which was wholly-owned and operated by the Company, for approximately $500.0 million. The Company operated the plant and owned a 47.5% share. The Company recorded a loss of approximately $13.9 million on the sale.

All assets subject to disposition continued to be utilized in operations of the Company. As such, no separate accounting treatment or classification has been given to such assets.

NOTE 15 - Environmental Costs, Mine Reclamation And Closure Costs

The Company's mining operations are subject to reclamation and closure requirements. Reclamation and closure costs are estimated based on engineering studies. The Company monitors these requirements and periodically revises its cost estimates to meet existing legal and regulatory requirements of the various jurisdictions in which it operates. The Company expenses current mine reclamation costs. Costs for reclamation are accrued using the units-of-production method such that estimated final mine reclamation and closure costs are fully accrued at completion of mining activities, except where the Company has decided to close a mine. When a mine is closed, the Company records the estimated cost to complete the mine closure and seeks recovery of any incremental costs through rates. The Company believes that it has adequately provided for its reclamation obligations, assuming ongoing operations of its mines. Total estimated final reclamation costs, including the Company's and minority interest joint owners' portions, for all mines with which the Company is involved was $184.3 million at March 31, 2002. These amounts are expected to be paid over the next 40 years.

The liabilities for environmental clean-up related costs are generally recorded on an undiscounted basis. These liabilities are recorded in the balance sheet in Deferred credits - Other at March 31, 2002 and 2001 as follows:

	March 31,	
(Millions of dollars)	2002	2001
Mine reclamation and closure costs (a)	$ 145.6	$ 163.1
Environmental remediation (b)	40.3	42.3
Nuclear decommissioning (c)	8.8	9.1
Total	$ 194.7	$ 214.5

(a) Amounts include the Company's and minority interest joint owners' portion of mine reclamation costs. Amount also includes $12.2 million and $10.7 million at March 31, 2002 and 2001, respectively, that is included in Current liabilities - Other.

(b) Expected to be paid over 19 years. Amount also includes $1.2 million and $0.9 million at March 31, 2002 and 2001, respectively, that is included in Current liabilities - Other.

(c) Expected to be paid over 22 years.

The Company had trust fund assets included in Deferred Charges and Other of $80.4 million and $85.1 million at March 31, 2002 and 2001, respectively, relating to mine reclamation, including minority interest joint owners' portion.

NOTE 16 - Commitments and Contingencies

Litigation - The Company and its subsidiaries are parties from time to time to various legal claims, actions and complaints, certain of which involve material amounts. Although the Company 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, management currently believes that disposition of these matters will not have a materially adverse effect on the Company's consolidated financial statements.

Environmental issues - The Company is subject to numerous environmental laws including: the Federal Clean Air Act, as enforced by the Environmental Protection Agency and various state agencies; the 1990 Clean Air Act Amendments; the Endangered Species Act, particularly as it relates to certain potentially endangered species of salmon; the Comprehensive Environmental Response, Compensation and Liability Act, relating to environmental cleanups; along with the Federal Resource Conservation and Recovery Act and the Clean Water Act relating to water quality. These laws could potentially impact future operations. For those contingencies identified at March 31, 2002, principally the Superfund sites where the Company has been or may be designated as a potentially responsible party and Clean Air Act matters, future costs associated with the disposition of these matters are expected to be addressed in future regulatory requests and, therefore, are not expected to be material to the Company's consolidated financial statements.

Hydroelectric relicensing - The Company's hydroelectric portfolio consists of 53 plants with a total capacity of 1,119 MW. Ninety-seven percent of the installed capacity is regulated by the FERC through 20 individual licenses. Nearly all of the Company's hydroelectric projects are in some stage of relicensing under the FPA. Hydro relicensing and the related environmental compliance requirements are subject to a high degree of change in estimation. However, the Company expects that these costs will be significant and consist primarily of future capital expenditures.

California and Enron Reserves - During 2001 and 2002, market conditions in California resulted in defaults of amounts due from California participants. In addition, Enron declared bankruptcy and defaulted on certain wholesale contracts. The Company provided full reserves for the California receivables and reserved the entire Enron receivable, net of the effect of applying its master netting agreement, in the aggregate amount of $14.0 million.

Construction and other - The Company has an ongoing construction program and, as a part of this program, substantial commitments have been made.

Leases - The Company has certain properties under leases with various expiration dates and renewal options. Rentals on lease renewals are subject to negotiation. Certain leases provide for options to purchase at fair market value. The Company is also committed to pay all taxes, expenses of operation (other than depreciation) and maintenance applicable to the leased property.

Net rent expense for the years ended March 31, 2002, 2001 and 2000, was $27.1 million, $8.7 million and $16.0 million, respectively. In 2002, the Company leased a new generating turbine that added $24.7 million to rent expense. Future minimum lease payments under noncancellable operating leases are $4.1 million, $3.7 million, $3.5 million, $3.5 million and $1.9 million for 2003 through 2007, respectively.

Future minimum lease payments under capital leases are $3.2 million, $3.4 million, $3.4 million, $3.4 million and $3.6 million for 2003 through 2007, respectively, and $55.9 million thereafter. The amount of interest in those lease payments is $45.3 million.

Future minimum lease payments on the West Valley City, Utah lease discussed in Note 3 are $12.5 million, $15.0 million, $15.0 million, $2.5 million and $- for 2003 through 2007, respectively.

The Company does not utilize "off-balance sheet" financing arrangements other than operating leases, which are accounted for in accordance with SFAS No. 13 "Accounting for Leases."

Jointly owned facilities - At March 31, 2002, Domestic Electric Operations' participation in jointly owned facilities was as follows:

(Millions of dollars)	Domestic Electric Operations' Share	Plant in Service	Accumulated Depreciation/ Amortization	Construction Work in Progress
Centralia Skookumchuck (a)	47.5%	$ 8.7	$ 4.9	$ -
Jim Bridger Units 1,2,3 and 4 (b)	66.7	830.8	392.9	6.2
Trojan (c)	2.5	-	-	-
Colstrip Units 3 and 4 (b)	10.0	234.4	99.7	4.6
Hunter Unit 1	93.8	280.8	122.4	1.3
Hunter Unit 2	60.3	198.9	87.6	5.2
Wyodak	80.0	304.3	130.1	0.4
Craig Station Units 1 and 2	19.3	152.8	72.5	2.2
Hayden Station Unit 1	24.5	40.0	14.0	0.2
Hayden Station Unit 2	12.6	25.9	9.9	0.1
Hermiston (d)	50.0	161.3	25.0	0.1
Foote Creek (b)	78.8	40.5	4.7	3.3
Other kilovolt lines and substations	Various	78.0	14.8	-
Unallocated acquisition adjustments (e)		141.2	46.7	-
Total		$2,497.6	$1,025.2	$23.6

(a) The Centralia plant was sold on May 4, 2000. The joint owners of the plant retained ownership in the Skookumchuck Dam and related facilities. For additional information on the sale, see Note 14.

(b) Includes kilovolt lines and substations.

(c) Plant, inventory, fuel and decommissioning costs totaling $16.8 million relating to the Trojan Plant were included in regulatory assets at March 31, 2002.

(d) Additionally, the Company has contracted to purchase the remaining 50% of the output of the plant.

(e) Represents the excess of the cost of the acquired interest in purchased facilities over their original net book value.

Under the joint agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. Domestic Electric Operations' portion is recorded in its applicable operations, maintenance and tax accounts, which is consistent with wholly owned plants.

On April 21, 2002, a failure occurred in the Swift power canal on the Lewis River in the state of Washington. The power canal and associated 70 MW hydroelectric facility are owned by Cowlitz County Public Utility District. Preliminary investigations suggest that the facility will be out of service for an extended period of time, possibly more than a year. This failure impacts the Company's owned and operated 240 MW Swift No. 1 hydroelectric facility by restricting both flow and generation flexibility ("shaping"). Test operations of Swift No. 1 indicate generation output will be temporarily reduced to two-thirds capacity due to physical and environmental constraints surrounding the canal failure. Swift No. 1 is currently generating at the two-thirds capacity level with limited shaping capabilities. The Company will continue to seek ways to mitigate the reduced capacity and recover other business losses. The impact of the Swift outage and plans for repair are being determined. A prompt return to full flow appears possible. This event is not expected to have a significant impact on the Company's financial position or results of operations.

Long-term wholesale sales and purchased power contracts - Domestic Electric Operations manages its energy resource requirements by integrating long-term firm, short-term and spot market purchases with its own generating resources to economically dispatch the system (within the boundaries of FERC requirements) and meet commitments for wholesale sales and retail load growth. The long-term wholesale sales commitments include contracts with minimum sales requirements of $338.4 million, $312.5 million, $268.1 million, $229.5 million and $191.5 million for the years 2003 through 2007, respectively. As part of its energy resource portfolio, Domestic Electric Operations acquires a portion of its power through long-term purchases and/or exchange agreements which require minimum fixed payments of $347.6 million, $334.1 million, $338.3 million, $335.1 million and $345.0 million for the years 2003 through 2007, respectively. The purchase contracts include agreements with the BPA, the Hermiston Plant and a number of co-generating facilities.

Excluded from the minimum fixed annual payments above are commitments to purchase power from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project annual costs (operating expenses and debt service). These costs are included in operations expense. Domestic Electric Operations is required to pay its portion of operating costs and its portion of the debt service, whether or not any power is produced. The arrangements provide for non-withdrawable power and the majority also provide for additional power, withdrawable by the districts upon one to five years' notice. For 2002, such purchases approximated 1.9% of energy requirements.

At March 31, 2002, Domestic Electric Operations' share of long-term arrangements with public utility districts was as follows:

Generating Facility	Year Contract Expires	Capacity (kW)	Percentage of Output	Annual Costs(a)
Wanapum	2009	155,444	18.9%	$ 7.0
Priest Rapids	2005	109,602	13.9	4.0
Rocky Reach	2011	64,297	5.3	3.1
Wells	2018	59,617	6.9	2.0
Total		388,960		$16.1

(a) Annual costs in millions of dollars. Includes debt service of $6.3 million. The Company's minimum debt service obligation at March 31, 2002 was $9.0 million, $9.0 million, $8.0 million, $10.0 million and $10.0 million for the years 2003 through 2007, respectively.

The Company has a 4.0% interest in the Intermountain Power Project (the "Project"), located in central Utah. The Company and the city of Los Angeles have agreed that the City will purchase capacity and energy from Company plants equal to the Company's 4.0% entitlement of the Project at a price equivalent to 4.0% of the expenses and debt service of the Project.

Short-term wholesale sales and purchased power contracts - At March 31, 2002, Domestic Electric Operations had short-term wholesale forward sales commitments that included contracts with minimum sales requirements of $153.2 million for the year 2003. At March 31, 2002, short-term forward purchase agreements require minimum fixed payments of $231.2 million for the year 2003.

Fuel contracts - Domestic Electric Operations has "take or pay" coal and natural gas contracts that require minimum fixed payments of $161.1 million, $156.3 million, $146.7 million, $131.5 million and $115.3 million for 2003 through 2007, respectively.

In May 1999, Domestic Electric Operations entered into a coal mining lease agreement for exclusive rights to mine the Mill Fork Tract in Emery County, Utah. The agreement calls for a lease bonus bid payment of $25.0 million, payable annually in March in installments of $5.0 million through 2003.

Resource management - The Company, as a public utility and a franchise supplier, has an obligation to manage resources to supply its customers. Rates charged to most customers are tariff rates authorized by regulatory agencies as discussed in Note 3.

NOTE 17 - Employment Benefit Plans

Retirement plans - The Company has pension plans covering substantially all employees. Benefits under the plan in the United States are based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from Social Security. Pension costs are funded annually by no more than the maximum amount that can be deducted for federal income tax purposes. At March 31, 2002, plan assets were primarily invested in common stocks, bonds and United States government obligations.

All permanent employees of Powercor engaged prior to October 4, 1994 were members of Division B or C of the Superannuation Fund (the "Fund") which provided defined benefits in the form of pensions (Division B) or lump sums (Division C). Both defined benefit Funds are closed to new members. Members who chose to contribute did so at rates of 3.0% or 6.0% of eligible salaries. Powercor employees engaged after October 4, 1994 were members of Division D of the Fund, which was a defined contribution fund in which members contributed up to 20.0% of eligible salaries. In 2001, Powercor made no contributions to Division B and C funds. In 2000, Powercor made contributions of $2.0 million to Division B and C funds. Powercor contributed to the Division D Fund at rates ranging from 6.0%-10.0% of eligible salaries in all years.

The net periodic pension (benefit) cost and significant assumptions are summarized as follows:

	Years Ended March 31,		
(Millions of dollars)	2002	2001	2000
Service cost	$ 14.9	$ 19.5	$ 27.6
Interest cost	80.1	82.4	81.7
Expected return on plan assets	(99.9)	(105.8)	(93.9)
Amortization of unrecognized net obligation	8.4	8.4	8.4
Unrecognized prior service cost	0.5	0.5	3.0
Unrecognized gain	(10.3)	(9.7)	(0.8)
Net periodic pension (benefit) cost	$ (6.3)	$ (4.7)	$ 26.0
Discount rate	7.5%	7.8%	5.5%-7.5%
Expected long-term rate of return on assets	9.3%	9.3%	7.5%-9.3%
Rate of increase in compensation levels	4.0%	4.0%	4.0%-4.5%

The change in the projected benefit obligation, change in plan assets and funded status are as follows:

(Millions of dollars)	March 31, 2002	2001
Change in projected benefit obligation		
Projected benefit obligation - beginning of period	$1,129.4	$1,142.4
Service cost	14.9	19.5
Interest cost	80.1	82.4
Foreign currency exchange rate changes	-	(9.3)
Plan participant contributions	-	0.5
Plan amendments	18.0 (a)	(23.2)(c)
Special termination benefits	0.8	81.0
Actuarial loss	7.2	30.1
Benefits paid	(129.6)	(128.4)
Divestiture	(41.5)(b)	(65.6)
Projected benefit obligation - end of period	$1,079.3	$1,129.4
Change in plan assets		
Plan assets at fair value - beginning of period	$1,152.6	$1,265.8
Foreign currency exchange rate changes	-	(8.8)
Actual return on plan assets	(147.7)	55.3
Plan participant contributions	-	0.5
Company contributions	7.3	33.7
Benefits paid	(129.6)	(128.4)
Divestiture	(56.4)(b)	(65.5)
Plan assets at fair value - end of period	$ 826.2	$1,152.6
Reconciliation of accrued pension cost and total amount recognized		
Funded status of the plan	$ (253.1)	$ 23.2
Unrecognized net loss (gain)	71.1	(208.8)
Unrecognized prior service cost (credit)	13.1	(4.4)
Unrecognized net transition obligation	41.2	49.6
Accrued pension cost	$ (127.7)	$ (140.4)
Accrued benefit liability	$ (169.0)	$ (140.4)
Intangible asset	41.3	-
Accrued pension cost	$ (127.7)	$ (140.4)

(a) Represents an increase in the Company's projected benefit obligation as a consequence of the ad hoc cost of living benefit increase for retired employees that was approved on March 13, 2002.

(b) Represents a reduction in the Company's projected benefit obligation and assets as a consequence of the transfer of obligation to a new plan being jointly administered by the IBEW Local Union 57 and the Company. The new plan was created according to negotiated agreements between the Union and the Company. As a result of these agreements, the nature of the Company's obligation changed from a fixed future benefit to a fixed percentage of pay commitment.

(c) Represents a reduction in the Company's projected benefit obligation as a consequence of an amended agreement with IBEW Local 57, under which employees under age 50 on July 1, 1999 receive their future service pension benefits from a new plan being jointly administered by the Union and the Company.

Employee Savings and Stock Ownership Plan - The Company has an employee savings and stock ownership plan that qualifies as a tax-deferred arrangement under the Internal Revenue Code. Participating United States employees may defer up to 20.0% of their compensation, subject to certain regulatory limitations. The Company matches 50.0% of employee contributions on amounts deferred up to 6.0% of total compensation with that portion vesting over five years. The Company makes an additional contribution of ScottishPower ADS to qualifying employees equal to a percentage of the employee's eligible earnings. These contributions are immediately vested. Company contributions to the savings plan were $16.8 million, $18.0 million and $18.7 million for the years ended March 31, 2002, 2001 and 2000, respectively, and represent amounts expensed for each period.

Other Postretirement Benefits - Domestic Electric Operations provides health care and life insurance benefits through various plans for eligible retirees on a basis substantially similar to those who are active employees. The cost of postretirement benefits is accrued over the active service period of employees. The transition obligation represents the unrecognized prior service cost and is being amortized over a period of 20 years. For those employees retired at January 1, 1994, the Company funds postretirement benefit expense on a pay-as-you-go basis and has an unfunded accrued liability of $181.6 million at March 31, 2002. For those employees retiring after January 1, 1994, the Company funds postretirement benefit expense through a combination of funding vehicles. The Company contributed nothing for the years ended March 31, 2002 and 2001 and $6.0 million for the year ended March 31, 2000. These funds are invested in common stocks, bonds and United States government obligations.

The net periodic postretirement benefit cost and significant assumptions are summarized as follows:

(Millions of dollars)	Years Ended March 31, 2002	2001	2000
Service cost	$ 5.2	$ 5.2	$ 6.5
Interest cost	28.6	27.7	24.5
Expected return on plan assets	(29.2)	(28.3)	(21.9)
Amortization of unrecognized net obligation	12.2	12.2	12.2
Unrecognized gain	(4.5)	(4.2)	(2.4)
Regulatory deferral	1.5	1.5	1.5
Net periodic postretirement benefit cost	$ 13.8	$ 14.1	$ 20.4
Discount rate	7.5%	7.8%	7.5%
Estimated long-term rate of return on assets	9.3%	9.3%	9.3%
Initial health care cost trend rate - under 65	10.5%	6.0%	6.6%
Initial health care cost trend rate - over 65	12.5%	6.5%	6.8%
Ultimate health care cost trend rate	5.0%	4.5%	4.5%

The change in the accumulated postretirement benefit obligation (the "APBO"), change in plan assets and funded status are as follows:

(Millions of dollars)	March 31, 2002	March 31, 2001
Change in accumulated postretirement benefit obligation		
Accumulated postretirement benefit obligation - beginning of period	$381.1	$347.0
Service cost	5.2	5.2
Interest cost	28.6	27.7
Plan participant contributions	5.4	4.7
Special termination benefits	-	16.9(a)
Actuarial loss (gain)	77.0	(0.3)
Benefits paid	(26.9)	(20.1)
Accumulated postretirement benefit obligation - end of period	$470.4	$381.1
Change in plan assets		
Plan assets at fair value - beginning of period	$287.1	$303.1
Actual return on plan assets	(18.0)	(10.7)
Company contributions	14.9	10.1
Plan participant contributions	5.4	4.7
Net benefits paid	(26.9)	(20.1)
Plan assets at fair value - end of period	$262.5	$287.1
Reconciliation of accrued postretirement costs and total amount recognized		
Funded status of the plan	$(207.9)	$ (94.0)
Unrecognized net loss (gain)	52.6	(76.2)
Unrecognized net transition obligation	131.2	143.5
Accrued postretirement benefit cost	$ (24.1)	$ (26.7)

(a) Represents the one-time charge for enhanced postretirement medical benefits for employees accepting the voluntary Workforce Transition Retirement Program offering in 2001.

The assumed health care cost trend rate gradually decreases over 5 to 8 years. The health care cost trend rate assumption has a significant effect on the amounts reported. Increasing the assumed health care cost trend rate by one percentage point would have increased the APBO as of March 31, 2002 by $26.3 million and the annual net periodic postretirement benefit costs by $1.8 million. Decreasing the assumed health care cost trend rate by one percentage point would have reduced the APBO as of March 31, 2002 by $24.3 million and the annual net periodic postretirement benefit costs by $1.7 million.

Postemployment Benefits - Domestic Electric Operations provides certain postemployment benefits to former employees and their dependants during the period following employment but before retirement. The costs of these benefits are accrued as they are incurred. Benefits include salary continuation, severance benefits, disability benefits and continuation of health care benefits for terminated and disabled employees and workers compensation benefits. Accrued costs for postemployment benefits were $5.4 million, $8.7 million and $7.4 million for the years ended March 31, 2002, 2001 and 2000, respectively.

Stock Option Incentive Plan - During 1997, the Company adopted a Stock Option Incentive Plan (the "Plan"). The exercise price of options granted under the Plan was 100.0% of the fair market value of the common stock on the day prior to the date of the grant. Stock options generally became exercisable in two or three equal installments on each of the first through third anniversaries of the grant date. The maximum exercise period under the Plan was ten years.

Upon completion of the Merger, all stock options granted prior to January 1999 became 100.0% vested. All outstanding stock options were converted into options to purchase ScottishPower ADS. Stock options to purchase ScottishPower ADS granted subsequent to the Merger vest over the same number of years as stock options granted prior to the Merger.

The table below summarizes the stock option activity under the Plan.

	Weighted Average Price	Number of Shares
PacifiCorp Stock		
Outstanding Options		
March 31, 1999	$21.35	6,080,285
Granted	17.19	871,900
Exercised	19.31	(61,500)
Forfeited	21.21	(614,276)
Outstanding Options		
November 28, 1999	20.80	6,276,409
Conversion to ScottishPower ADS at 0.58 ADS		
per PacifiCorp share		(6,276,409)
Outstanding Options		-
ScottishPower ADS		
Outstanding Options		
November 29, 1999	35.87	3,633,481
Granted	29.37	1,504,037
Exercised	-	-
Forfeited	36.89	(369,363)
Outstanding Options		
March 31, 2000	33.73	4,768,155
Granted	25.06	114,150
Exercised	30.05	(75,885)
Forfeited	33.90	(1,079,400)
Outstanding Options		
March 31, 2001	33.49	3,727,020
Granted	25.68	824,750
Exercised	26.94	(24,665)
Forfeited	32.74	(560,109)
Outstanding Options		
March 31, 2002	32.01	3,966,996

At March 31, 2002, options for 2,773,244 ScottishPower ADS were exercisable with a weighted average exercise price of $34.14 per share. The weighted average life of the options outstanding at March 31, 2002 was six years. At March 31, 2001, options for 2,496,389 ScottishPower ADS were exercisable with a weighted average exercise price of $35.43 per share. The weighted average life of the options outstanding at March 31, 2001 was six years. As permitted by SFAS No. 123, the Company has elected to account for these options under APB No. 25. Accordingly, no compensation expense has been recognized for these options. Had the Company determined compensation cost based on the fair value at the grant date for all stock options vesting in each period under SFAS No. 123, the Company's net income would have been reduced to the pro forma amounts below:

(Millions of dollars)	Years Ended March 31, 2002	2001	2000
Net income (loss) as reported	$327.3	$(88.2)	$83.7
Pro forma	$325.1	$(91.6)	$78.9

The fair value of options granted was $3.4 million, $0.4 million and $14.0 million in 2002, 2001 and 2000, respectively. The fair value of each option grant was estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used:

	2002	2001	2000
Dividend yield	6.7%	6.4%	5.0%
Risk-free interest rate	4.8%	4.9%	5.0%
Volatility	30.0%	23.5%	30.0%
Expected life of the options (years)	5	10	10

NOTE 18 - Concentration Of Customers

During 2002, no single retail customer accounted for more than 1.4% of the Company's Domestic Electric Operations' retail utility revenues and the 20 largest retail customers accounted for 13.8% of total retail electric revenues. The geographical distribution of the Company's Domestic Electric Operations' retail operating revenues for the year ended March 31, 2002 was Utah, 39.1%; Oregon, 32.5%; Wyoming, 12.6%; Washington, 7.9%; Idaho, 5.6%; and California, 2.3%.

NOTE 19 - Segment Information

The Company operated in two business segments (excluding other and discontinued operations): Domestic Electric Operations and Australian Electric Operations. The Company identified the segments based on management responsibility within the United States and Australia. Domestic Electric Operations includes the regulated retail and wholesale electric operations in the six western states in which it operates. Australian Electric Operations included the deregulated electric operations in Australia. Other Operations consisted of PFS, the western energy trading activities and other energy development businesses, as well as the activities of Holdings, including financing costs. Holdings and its subsidiaries, including PFS, were transferred to PHI in February 2002 as discussed in Note 4.

(Millions of dollars)	Total Company	Domestic Electric Operations	Australian Electric Operations	Discontinued Operations	Other Operations & Eliminations
Year ended March 31, 2002					
Net sales and revenue (all external)	$ 4,259.2	$ 4,246.6	$ -	$ -	$ 12.6
Depreciation and amortization	403.0	401.3	-	-	1.7
Interest expense	227.7	233.3	-	-	(5.6)
Interest income	23.6	5.0	-	-	18.6
Income tax expense	176.1	138.6	-	-	37.5
Income from continuing operations	293.4	245.5	27.4	-	20.5
Gain from discontinued operations	146.7	-	-	146.7	-
Cumulative effect of accounting change	(112.8)	(112.8)	-	-	-
Total assets	10,671.3	10,671.3	-	-	-
Investments in nonconsolidated affiliates	11.0	11.0	-	-	-
Capital spending	505.3	505.3	-	-	-
Year ended March 31, 2001					
Net sales and revenue (all external)	$ 5,056.7	$ 4,535.2	$ 399.3	$ -	$ 122.2
Depreciation and amortization	429.0	389.0	36.4	-	3.6
Interest expense	290.4	252.3	37.5	-	0.6
Interest income	31.6	9.6	-	-	22.0
Losses of nonconsolidated affiliates	(1.4)	-	(1.4)	-	-
Income tax expense	180.4	87.6	15.3	-	77.5
(Loss) income from continuing operations	(88.2)	128.0	(187.2)	-	(29.0)
Total assets	11,133.8	11,050.7	-	-	83.1
Investments in nonconsolidated affiliates	7.2	7.0	-	-	0.2
Capital spending	491.0	376.1	47.7	-	67.2
Year ended March 31, 2000					
Net sales and revenue (all external)	$ 3,986.9	$ 3,292.2	$ 617.6	$ -	$ 77.1
Depreciation and amortization	441.3	379.9	57.9	-	3.5
Interest expense	341.4	268.1	58.4	-	14.9
Interest income	17.1	5.0	-	-	12.1
Losses of nonconsolidated affiliates	(2.6)	-	(2.6)	-	-
Income tax expense (benefit)	134.0	125.2	24.1	-	(15.3)
Income from continuing operations	82.6	29.8	39.0	-	13.8
Income from discontinued operations	1.1	-	-	1.1	-
Total assets	12,305.1	11,243.3	1,781.0	-	(719.2)
Investments in nonconsolidated affiliates	116.0	6.1	106.9	-	3.0
Capital spending	578.0	510.0	66.0	-	2.0

SELECTED FINANCIAL INFORMATION (UNAUDITED)

(Millions of dollars, except per share and employee amounts)		Years Ended March 31,		Three Months Ended March 31,		Years Ended December 31,
	2002	2001	2000	1999	1998	1997
Revenues						
Domestic Electric Operations	$4,246.6	$4,535.2	$3,292.2	$ 807.2	$4,845.1	$3,706.9
Australian Electric Operations	-	399.3	617.6	147.0	614.5	716.2
Other Operations (a)	12.6	122.2	77.1	5.6	120.8	125.8
Total	$4,259.2	$5,056.7	$3,986.9	$ 959.8	5,580.4	$4,548.9
Income (Loss) from Operations						
Domestic Electric Operations	$ 622.5	$ 454.1	$ 587.8	$ 195.6	$ 571.8	$ 601.3
Australian Electric Operations	27.4	(133.1)	125.1	34.8	114.5	150.5
Other Operations (a)	15.0	19.8	(7.8)	(2.9)	(5.5)	58.9
Total	$ 664.9	$ 340.8	$ 705.1	$ 227.5	$ 680.8	$ 810.7
Net (Loss) Income	$ 327.3	$ (88.2)	$ 83.7	$ 91.3	$ (36.1)	$ 663.7
Earnings Contribution (Loss)						
Continuing operations						
Domestic Electric Operations	$ 232.8	$ 110.1	$ 10.9	$ 75.4	$ 130.5	$ 165.5
Australian Electric Operations	27.4	(187.2)	39.0	10.4	13.0	54.2
Other Operations (a)	20.5	(29.0)	13.8	0.7	(52.2)	(9.6)
Total	280.7	(106.1)	63.7	86.5	91.3	210.1
Discontinued operations (b)	146.7	-	1.1	-	(146.7)	446.8
Cumulative effect of accounting change (c)	(112.8)	-	-	-	-	-
Extraordinary item (d)	-	-	-	-	-	(16.0)
Total	$ 314.6	$ (106.1)	$ 64.8	$ 86.5	$ (55.4)	$ 640.9
Common dividends declared per share	$ 0.81	$ 1.31	$ 0.58	$ 0.27	$ 1.08	$ 1.08
Common dividends paid per share	1.00	1.12	0.85	0.27	1.08	1.08

		March 31,			December 31,	
	2002	2001	2000		1998	1997
Capitalization						
Short-term debt	$ 321.0	$ 291.7	$ 295.9		$ 559.8	$ 554.6
Long-term debt	3,553.8	2,906.9	4,045.7		4,383.5	4,237.2
Preferred Securities of Trusts	341.5	341.2	340.9		340.5	340.4
Junior subordinated debentures	-	-	175.8		175.8	175.8
Redeemable preferred stock	74.2	175.0	175.0		175.0	175.0
Preferred stock	41.3	41.5	41.5		66.4	66.4
Common equity	2,891.9	3,414.4	3,879.9		3,956.3	4,320.9
Total	$ 7,223.7	$ 7,170.7	$ 8,954.7		$ 9,657.3	$ 9,870.3
Total Assets	$10,671.3	$11,133.8	$12,305.1		$12,988.5	$13,627.0
Total Employees	6,287	6,626	8,832		9,120	10,087

(a) Other Operations includes the operations of PPM and PKE until their transfer in March 2001, Pacific Generation Company ("PGC"), a wholly-owned subsidiary of the Company until its sale in December 1997, and PFS, as well as the activities of Holdings, including financing costs, and elimination entries, until their transfer in February 2002.

(b) Amounts in 2002 represent the collection of a contingent note receivable relating to the discontinued operations of a former mining and resource development business, NERCO. The 2000 amount represents discontinued operations of TPC.

(c) Represents the effect of implementation of SFAS 133.

(d) Extraordinary item included a regulatory asset impairment pertaining to generation resources that were allocable to operations in California and Montana.

DOMESTIC ELECTRIC OPERATIONS (UNAUDITED)

(Millions of dollars, except as noted)	Years Ended March 31, 2002	2001	2000	Three Months Ended March 31, 1999	Years Ended December 31, 1998	1997	2002 to 2001 Percentage Comparison	5-Year Compound Annual Growth
Revenues								
Residential	$ 901.7	$ 852.1	$ 798.7	$ 231.2	$ 806.6	$ 814.0	5.8%	2.1%
Commercial	747.7	710.5	667.2	159.0	653.5	640.9	5.2	3.1
Industrial	705.1	730.1	694.5	151.8	705.5	709.9	(3.4)	(0.1)
Other	34.5	32.5	30.4	7.2	30.2	31.7	6.2	1.7
Retail sales	2,389.0	2,325.2	2,190.8	549.2	2,195.8	2,196.5	2.7	1.7
Wholesale sales	1,684.7	2,078.1	1,029.1	240.0	2,583.6	1,428.0	(18.9)	3.4
Other	172.9	131.9	72.3	18.0	65.7	82.4	31.1	16.0
Total	4,246.6	4,535.2	3,292.2	807.2	4,845.1	3,706.9	(6.4)	2.8
Expenses								
Purchased power	2,038.8	2,478.4	957.9	209.7	2,497.0	1,296.5	(17.7)	9.5
Fuel	490.9	491.0	512.3	126.5	506.6	486.2	-	0.2
Other operations and maintenance	560.6	534.8	554.2	114.0	461.4	473.6	4.8	3.4
Administrative and general	245.6	121.0	200.8	46.9	233.9	227.8	103.0	1.5
Depreciation and amortization	401.3	389.0	379.9	88.6	353.5	353.5	3.2	2.6
Taxes, other than income taxes	90.7	97.5	99.3	25.9	97.5	97.6	(7.0)	(1.5)
Unrealized gain on SFAS No. 133 - derivative instruments	(182.8)	-	-	-	-	-	*	*
Special charges	-	-	-	-	123.4	170.4	-	*
Operating expenses	3,645.1	4,111.7	2,704.4	611.6	4,273.3	3,105.6	(11.3)	3.2
Other operating income	(21.0)	(30.6)	-	-	-	-	(31.4)	*
Total	3,624.1	4,081.1	2,704.4(b)	611.6	4,273.3	3,105.6	(11.2)	3.1
Income from Operations	622.5	454.1	587.8	195.6	571.8	601.3	37.1	0.7
Interest expense	233.3	252.3	268.1	71.0	319.1	319.0	(7.5)	(6.1)
Interest capitalized	(6.9)	(12.9)	(20.2)	(3.4)	(14.5)	(12.2)	(46.5)	(10.8)
Merger costs	-	9.3	190.5	-	13.2	-	*	*
Minority interest and other	12.0	(10.2)	(5.6)	(6.0)	1.3	(5.8)	*	*
Income tax expense	138.6	87.6	125.2	53.8	102.9	112.0	58.2	4.4
Income before cumulative effect of accounting change	245.5	128.0	29.8	80.2	149.8	188.3	91.8	5.4
Cumulative effect of accounting change	(112.8)	-	-	-	-	-	*	*
Net Income	132.7	128.0	29.8	80.2	149.8	188.3	3.7	(6.8)
Preferred Dividend Requirement	(12.7)	(17.9)	(18.9)	(4.8)	(19.3)	(22.8)	(29.1)	(11.0)
Earnings Contribution (c)	$ 120.0	$ 110.1	$ 10.9	$ 75.4	$ 130.5	$ 165.5	9.0	(6.2)
Total assets	$10,671.3	$11,050.7	$11,243.3		$12,051.8	$12,740.7	(3.4)	1.2
Capital spending	$ 505.3	$ 376.1	$ 510.0		$ 539.0	$ 490.0	34.4	0.6

*Not a meaningful number.

(a) Includes a $43.5 million asset write-back from receipt of a regulatory order and a $13.9 million loss on the sale of the Centralia plant and mine.

(b) Includes Merger costs of $16.0 million.

(c) Does not reflect elimination of interest on intercompany borrowing arrangements and includes income taxes on a separate-company basis.

DOMESTIC ELECTRIC OPERATIONS STATISTICS (UNAUDITED)

	Years Ended March 31, 2002	2001	2000	Three Months Ended March 31, 1999	Years Ended December 31, 1998	1997	2002 to 2001 Percentage Comparison	5-Year Compound Annual Growth
Energy Sales (Thousands of MWh)								
Residential	13,395	13,455	13,028	3,773	12,969	12,902	(0.4)%	0.8%
Commercial	13,810	13,634	12,827	2,993	12,299	11,868	1.3	3.1
Industrial	19,611	20,659	20,488	4,627	20,966	20,674	(5.1)	(1.1)
Other	711	705	663	153	651	705	0.9	0.2
Retail sales	47,527	48,453	47,006	11,546	46,885	46,149	(1.9)	0.6
Wholesale sales	24,438	27,502	34,327	9,636	94,077	59,143	(11.1)	(16.2)
Total	71,965	75,955	81,333	21,182	140,962	105,292	(5.3)	(7.3)
Energy Source								
Coal	62.6%	56.0%	58.0%	54.0%	51.0%	43.0%	11.8	7.8
Hydroelectric	4.9	4.0	7.0	8.0	6.0	5.0	22.5	(0.4)
Other	0.2	4.0	3.0	3.0	2.0	2.0	(95.0)	(36.9)
Purchase and exchange contracts	32.3	36.0	32.0	35.0	41.0	50.0	(10.3)	(8.4)
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%		
Number of Retail Customers (Thousands)								
Residential	1,296	1,278	1,252	1,233	1,255	1,228	1.4	1.1
Commercial	182	179	174	169	174	170	1.7	1.4
Industrial	35	35	35	35	36	36	-	(0.6)
Other	4	4	4	5	5	4	-	-
Total	1,517	1,496	1,465	1,442	1,470	1,438	1.4	1.1
Residential Customers								
Average annual usage (kWh)	10,411	10,614	10,463		10,443	10,644		
Average annual revenue per customer	$ 701	$ 672	$ 641		$ 650	$ 672		
Revenue per kWh	$0.67	$0.63	$0.61		$0.62	$0.63		
Miles of Line								
Transmission	14,900	14,900	14,900		15,000	15,000	-	(0.1)
Distribution								
-- overhead	43,800	43,700	43,600		45,000	45,000	0.2	(0.5)
-- underground	12,500	11,900	10,900		10,000	10,000	5.0	4.6
System Peak Demand (MW)								
Net system load (a)								
-- summer	7,899	8,056	7,570		7,666	7,110	(5.6)	1.4
-- winter	7,688	7,475	7,115		7,909	7,403	(2.9)	(0.4)
Total firm load (b)								
-- summer	10,029	10,115	10,494		11,629	10,871	(0.9)	(1.6)
-- winter	9,511	9,592	10,622		12,301	10,830	(0.8)	(2.6)
System Capability (megawatts) (c)								
-- summer	11,015	11,327	13,457		12,632	12,343	(2.8)	(2.2)
-- winter	11,050	11,270	13,184		13,427	12,618	(2.0)	(2.6)

(a) Excludes off-system sales.

(b) Includes firm off-system sales.

(c) Generating capability, short-term and long-term firm purchases at time of firm peak.

AUSTRALIAN ELECTRIC OPERATIONS (UNAUDITED)(a)

(Millions of dollars, except as noted)	2002	Years Ended March 31, 2001[b]	2000[b]	Three Months Ended March 31, 1999	Years Ended December 31, 1998	1997
Revenue	$ -	$ 399.3	$ 617.6	$ 147.0	$ 614.5	$ 716.2
Expenses						
Purchased power	-	157.6	260.0	59.0	255.0	308.5
Other operations and maintenance	-	65.9	104.3	25.2	140.1	134.0
Administrative and general	-	54.1	68.8	12.5	45.7	54.9
Depreciation and amortization	-	36.4	57.9	15.2	58.2	67.1
Taxes, other than income taxes	-	0.8	1.5	0.3	1.0	1.2
Total	-	314.8	492.5	112.2	500.0	565.7
(Gain) loss on sale of Australian electric operations	(27.4)	217.6	-	-	-	-
Income (loss) from Operations	27.4	(133.1)	125.1	34.8	114.5	150.5
Interest expense	-	37.5	58.4	14.4	57.9	63.5
Equity in losses of Hazelwood	-	1.4	2.6	3.7	5.5	2.9
Other (income) expense - net	-	(0.1)	1.0	(0.1)	30.4	(2.4)
Income tax expense	-	15.3	24.1	6.4	7.7	32.3
Earnings (loss) Contribution	$ 27.4	$(187.2)	$ 39.0	$ 10.4	$ 13.0	$ 54.2
Total assets	$ -	$ -	$1,781.0		$1,663.6	$1,794.2
Capital spending	$ -	$ 47.7	$ 66.0		$ 75.0	$ 84.0

(a) Results of operations are included until the dates of disposal, September 6, 2000 for Powercor and November 17, 2000 for Hazelwood.

(b) Australian Electric Operations' financial results for the period from January 1, 2000 to the dates of sale are included in the Company's financial results for the year ended March 31, 2001. Australian Electric Operations' financial results for the year ended December 31, 1999 are included in PacifiCorp's consolidated results for the year ended March 31, 2000. See Note 1.

OTHER OPERATIONS (UNAUDITED)

Other Operations include the operations of PFS, PGC, the western United States energy trading activities of PPM and several start-up-phase ventures, as well as the activities of Holdings, including financing costs. PGC assets were sold on November 5, 1997 and a majority of the real estate assets of PFS were sold during May 1998. The Company transferred its interest in two non-utility energy companies to an affiliated entity, PHI, in March 2001 and transferred its interest in Holdings to PHI in February 2002.

		Years Ended March 31,		Three Months Ended March 31,	Years Ended December 31,	
(Millions of dollars)	2002	2001	2000	1999	1998	1997
Earnings (loss) Contribution						
PFS	$ 21.7	$ (30.9)	$ 15.5	$ (0.4)	$ 8.1	$ 30.2
PGC	-	-	-	-	-	10.4
Net gain on swap settlement and debt repayment expense	-	19.9	-	-	-	-
Holdings and other	(1.2)	(18.0)	(1.7)[a]	1.1	(60.3)	(50.2)
Total	$ 20.5	$ (29.0)	$ 13.8	$ 0.7	$(52.2)	$ (9.6)
Total Assets						
PFS	$ -	$ 341.2	$ 427.0		$ 423.3	$ 699.0
Holdings and other	-	(258.1)	(1,146.2)		(1,150.2)	(1,606.9)
Total	$ -	$ 83.1	$ (719.2)		$ (726.9)	$ (907.9)
Capital spending	$ -	$ 67.2	$ 2.0		$ 53.0	$ 140.0

(a) Includes $3.1 million in Merger costs for the year ended March 31, 2000.

SUPPLEMENTAL INFORMATION

QUARTERLY FINANCIAL DATA (UNAUDITED)

(Millions of dollars, except per share amounts)	June 30	September 30	December 31	March 31
			Quarters Ended	
2002				
Revenues	$1,281.6	$1,244.2	$ 884.8(b)	$ 848.6(b)
Income from operations	301.7(a)	5.5	131.0	226.7
Income (loss) from continuing operations	164.3	(30.2)	46.3	113.0
Discontinued operations	146.7	-	-	-
Cumulative effect of accounting change	(112.8)	-	-	-
Net income (loss)	198.2	(30.2)	46.3	113.0
Earnings (loss) on common stock	193.8	(34.6)	44.4	111.0
Common dividends declared per share	$ 0.27	$ 0.27	$ -	$ 0.27
Common dividends paid per share	0.46	0.27	-	0.27
2001				
Revenues	$1,029.5	$1,431.9	$1,360.3	$1,235.0
(Loss) income from operations	(23.7)(c)	139.5(d)	75.2 (e)	149.8(g)
Net (loss) income	(134.7)	52.7	(7.6)(f)	1.4(h)
(Loss) earnings on common stock	(139.3)	48.1	(12.1)	(2.8)
Common dividends declared per share	$ 0.77	$ 0.27	$ 0.27	$ -
Common dividends paid per share	0.50	0.27	0.27	0.08

(a) Includes $178.1 million gain on application of SFAS No. 133 and $27.4 million gain on the sale of the Australian Electric Operations.

(b) Short term and spot market Wholesale sales averaged $34.2 per MWh in the third quarter of 2002 compared to $105.3 per MWh in 2001 and averaged $24.6 per MWh in the fourth quarter of 2002 compared to $180.8 per MWh in 2001.

(c) The Company recorded an impairment of $188.4 million after-tax in anticipation of the loss on the sale of the Company's indirect ownership of Powercor and the Company's 19.9% interest in Hazelwood. See Note 14.

(d) The Company established $25.0 million in regulatory assets resulting from successful resolution of previously denied costs addressed in the Utah rate order received in May 2000. The Company recorded an additional loss of $8.3 million after-tax upon the completion of the sale of its indirect ownership of Powercor. See Notes 3 and 14.

(e) Increases in purchased power expenses exceeded the increases in revenues by $137.1 million. Purchased power expense increased as a result of the continuing increase in demand, generation outages and lower hydro generation. This increase is net of $16.0

million of accounting deferrals received from the Wyoming Commission for power cost variances.

(f) The Company reversed $28.0 million in alternative fuel tax credits because its tax liability was not sufficient to utilize those credits.

(g) Increases in purchased power expense exceeded the increases in revenues by $26.8 million net of accounting deferrals of $123.0 million pretax relating to accounting orders received from the commissions in Utah, Oregon, Wyoming, and Idaho for power cost variances. See Note 3.

(h) Includes a $66.2 million tax reserve relating to reevaluation of tax liabilities from settled and ongoing tax examinations.

A significant portion of the operations are of a seasonal nature. In the western portion, customer demand peaks in the winter months due to heating requirements. In the eastern portion, customer demand peaks in the summer when irrigation and cooling systems are heavily used.

See Note 4 for information regarding discontinued operations.

On March 31, 2002, there was one common shareholder of record.

<ARTICLE>	Exhibit G Data Statement	
<LEGEND>	THIS SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM (Identify financial statements) AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS	
<RESTATED>		
<CIK>	0000075594	
<NAME>	PACIFICORP	
<SUBSIDIARY>		
< NUMBER>		
< NAME>		
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<CURRENCY>		
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<PERIOD-END>	03/31/02	
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<NET-INCOME>		Annual report or 10-Q income statement - INCOME BEFORE INT EXP LESS INTEREST EXPENSE PLUS DISC OPS
<TOTAL-ASSETS>		Annual report or 10-Q balance sheet - Total Assets
<TOTAL-CURRENT-ASSETS>		Annual report or 10-Q balance sheet - Total current assets
<TOTAL-DEFERRED-CHARGES>		Annual report or 10-Q balance sheet - Deferred charges
<OTHER-ASSETS>		Annual report or 10-Q balance sheet - Total Other Assets less Investments, Intangible Assets and Deferred Charges
<TOTAL-NET-UTILITY-PLANT>		F&O line #21 (Receive from Rick Hanson if no F&O available)
<OTHER-PROPERTY-AND-INVEST>		Monthly Package (Net plant less net utility plant above)-Other nonutility plant in service PLUS Investment in & advances PLUS Intangible Assets
<CAPITAL-SURPLUS-PAID-IN>		Annual report or 10-Q balance sheet
<RETAINED-EARNINGS>		Annual report or 10-Q balance sheet - Retained Earnings
<TOTAL-COMMON-STOCKHOLDERS-EQ>		Annual report or 10-Q balance sheet - Total Common Equity
<PREFERRED-MANDATORY>		Annual report or 10-Q balance sheet - Preferred Stock Subject to Mandatory Redemption
<PREFERRED>		Annual report or 10-Q balance sheet - Preferred Stock
<COMMON>		Annual report or 10-Q balance sheet - Common Shareholder Capital + Guarantee of ESOP+Cum Curr. Trans. Adj.+FAS 115
<LONG-TERM-DEBT-NET>		Monthly package balance sheet detail - Long-term Debt (Do not include Capital Lease Obligations)
<SHORT-TERM-NOTES>		Monthly package balance sheet detail - Notes Payable (Current Liabilities) Less Commercial Paper
<LONG-TERM-NOTES-PAYABLE>		N/A
<COMMERCIAL-PAPER-OBLIGATIONS>		PacifiCorp/PHI Investment & Debt Short-Term Status Report plus Balance Sheet Elim. (Hermiston - no longer applicable)
<LONG-TERM-DEBT-CURRENT-PORTION>		Monthly package balance sheet detail - Long-term debt currently maturing (Do not include Capital Lease Obligations)
<PREFERRED-STOCK-CURRENT>		N/A
<CAPITAL-LEASE-OBLIGATIONS>		Monthly package balance sheet detail - Capital lease obligations
<LEASES-CURRENT>		Monthly package balance sheet detail - Capital lease obligations currently maturing (if negative = zero)
<OTHER-ITEMS-CAPITAL-AND-LIAB>		Annual report or 10-Q balance sheet - All other liabilities and capitalizaiton
<TOT-CAPITALIZATION-AND-LIAB>		Annual report or 10-Q balance sheet - Total Capitalization and Liabilities

<GROSS-OPERATING-REVENUE>		Annual report or 10-Q income statement - Total Revenues
<INCOME-TAX-EXPENSE>		Annual report or 10-Q income statement - Income Taxes
<OTHER-OPERATING-EXPENSES>		Annual report or 10-Q income statement - Total Operating Expenses
<TOTAL-OPERATING-EXPENSES>		Annual report or 10-Q income statement - Income Taxes PLUS Total Operating Expenses
<OPERATING-INCOME-LOSS>		Annual report or 10-Q income statement - GROSS OPERATING REVENUE LESS OPERATING EXPENSES
<OTHER-INCOME-NET>		Annual report or 10-Q income statement - Interest Expense LESS Total Interest expense and other
<INCOME-BEFORE-INTEREST-EXPENSE>		Annual report or 10-Q income statement - OPERATING INCOME PLUS OTHER INCOME
<TOTAL-INTEREST-EXPENSE>		Annual report or 10-Q income statement - Interest expense
<PREFERRED-STOCK-DIVIDENDS>		Annual report or 10-Q income statement - Preferred dividend requirement
<EARNINGS-AVAILABLE-FOR-COMMON>		Annual report or 10-Q income statement - NET-INCOME LESS PREFERRED-STOCK-DIVIDENDS
<COMMON-STOCK-DIVIDENDS>		Annual report or 10-Q cash flow - Common Dividends Paid Electric Cash Flow ONLY
<TOTAL-INTEREST-ON-BONDS>		Per Richard Fewel Net Interest Expense report (Formerly from F & O line 43 Interest Paid on Bonds 12 months ended Electric Op
<CASH-FLOW-OPERATIONS>		Annual report or 10-Q cash flow - Net cash provided by operating activities
<EPS-PRIMARY>	0.00	Annual report or 10-Q income statement - Net income per common share
<EPS-DILUTED>	0.00	Annual report or 10-Q income statement - Net income per common share

EXHIBIT H

CORPORATE CHART AS OF 3/31/2002

Company	Percentage of Ownership
Scottish Power plc	All 100% except as noted
ScottishPower UK plc (FUCO)	
ScottishPower Distribution Limited	
Scottish Electricity Settlements Limited (50)	
ScottishPower Dataserve Limited	
ScottishPower Transmission Limited	
ScottishPower Energy Retail Limited	
N.E.S.T. Makers Limited (50)	
ScottishPower Gas Limited	
ScottishPower Power Systems Limited	
Core Utility Solutions Limited (50)	
ScottishPower Generation Limited	
South Coast Power Limited (50)	
SMW Limited	
Shoreham Operations Company Limited (50)	
Scotash Limited (50)	
Beaufort Energy Limited	
CRE Energy Limited	
Wind Resources Limited (45)	
Carland Cross Limited	
Coal Clough Limited	
Celt Power Limited (50)	
Emerald Power Generation Limited	
ScottishPower Energy Trading (Agency) Limited	
ScottishPower Energy Trading Limited	
ScottishPower Investments Limited	
ScottishPower Overseas Holdings Limited (1)	
ScottishPower Insurance Limited	
ScottishPower Leasing Limited	
Genscot Limited	
SP Manweb plc (FUCO)	
ScottishPower Share Scheme Trustees Limited	
ScottishPower Sharesave Trustees Limited	
ScottishPower Overseas Holdings Limited (99)	
PacifiCorp Energy Canada Ltd.	
Aspen 4 Limited	
Southern Water plc	
Bowsprit Holdings Limited	

Bowsprit Property Development Limited
Monk Rawling Limited
Coastal Wastewater Consultants Limited (50)
E S Taylor (Worthing) Holdings Limited
James Leppard & Sons Limited
Taylor Plant & Haulage Limited
Taylors Glass & Waste Recycling Limited
TES Environmental Services Limited
Ecoclear Limited
Linemicro Limited
Pipeworks Limited
ScottishPower Group Money Purchase Pension Scheme Limited
Southern Science Limited
Southern Water Executive Pension Scheme Trustees Limited
Southern Water Technologies Limited
Southern Water Industries Limited
Southern Water Pension Trustees Limited
Southern Water Services Group Holdings Limited
SWS Holdings Limited
Southern Water Services Limited
Southern Water Services Finance plc
Timber Clear Limited
Water Working Limited
ScottishPower NA 1 Limited
ScottishPower NA 2 Limited
NA General Partnership
PacifiCorp Holdings Inc.
Pacific Klamath Energy, Inc.
PacifiCorp Power Marketing, Inc.
MAIN Wind 1 LLC
MAPP Wind 1 LLC
Phoenix Wind Power LLC
Klamath Energy LLC
Klamath Generation LLC
West Valley Leasing Company LLC
West Valley Generation LLC
Enstor, Inc.
CityGate, LLC
Columbia Gas Storage, LLC
Delta Gas Storage LLC
PacifiCorp
Energy West Mining Company
Glenrock Coal Company
Interwest Mining Company
Pacific Minerals, Inc.
Bridger Coal Company (66.66)

PacifiCorp Future Generations
Canopy Botanical, Inc.(77.85)
Canopy Botanical SRL (49)
Rainforest Exquisite Products (26)
PacifiCorp Group Holdings Company
PACE Group, Inc.
PacifiCorp Development Company
PacifiCorp Energy, Inc.
PacifiCorp Energy Services, Inc.
PacifiCorp Energy Ventures, Inc.
PacifiCorp Trans, Inc.
PacifiCorp Financial Services, Inc.
CS Holdings, Inc.
Koala FSC, Ltd.
Leblon Sales Corporation
Pacific Development (Property), Inc.
Pacific Harbor Capital, Inc.
PFI International, Inc.
PHC Properties Corporation
PNF Holdings, Inc.
VCI Acquisition Co.
PacifiCorp International Group Holdings Company
PacifiCorp Hazelwood Pty. Ltd.
Hazelwood Australia, Inc.
Hazelwood Ventures, Inc.
Hazelwood Finance LP(12.5)
PacifiCorp UK Development Corporation