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

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended June 30, 2002
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number	Name of Registrant; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street - 37th Floor P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	23-2990190
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 10 South Dearborn Street - 37th Floor P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-4321	36-0938600
1-1401	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348 (610) 765-8200	23-3064219

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [_].

The number of shares outstanding of each registrant's common stock as of August 1, 2002 was as follows:

Exelon Corporation Common Stock, without par value	322,874,719
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,398
PECO Energy Company Common Stock, without par value	170,478,507
Exelon Generation Company, LLC not applicable	

TABLE OF CONTENTS

Filing Format

This combined Form 10-Q is being filed separately by Exelon Corporation, Commonwealth Edison Company, PECO Energy Company and Exelon Generation Company, LLC (Registrants). Information contained herein relating to any individual registrant has been filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant.

Forward-Looking Statements

Except for the historical information contained herein, certain of the matters discussed in this Report are forward-looking statements that are subject to risks and uncertainties. The factors that could cause actual results to differ materially include those discussed herein as well as those listed in Note 8 of Notes to Consolidated Financial Statements, those discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations--Outlook" in Exelon Corporation's 2001 Annual Report, those discussed in "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Exelon Generation Company, LLC's Registration Statement on Form S-4, Reg. No. 333-85496 and other factors discussed in filings with the Securities and Exchange Commission by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. The Registrants undertake no obligation to publicly release any revision to forward-looking statements to reflect events or circumstances after the date of this Report.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(in millions, except per share data)	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
OPERATING REVENUES	$3,519	$3,616	$ 6,876	$ 7,439
OPERATING EXPENSES				
Purchased Power	699	754	1,311	1,385
Purchased Power from Unconsolidated Affiliate	60	12	116	22
Fuel	364	409	860	1,098
Operating and Maintenance	1,070	1,134	2,137	2,192
Depreciation and Amortization	332	362	667	740
Taxes Other Than Income	181	153	367	321
Total Operating Expense	2,706	2,824	5,458	5,758
OPERATING INCOME	813	792	1,418	1,681
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(241)	(289)	(490)	(581)
Distributions on Preferred Securities of Subsidiaries	(11)	(12)	(23)	(23)
Equity in Earnings of Unconsolidated Affiliates, net	9	7	22	25
Other, net	194	44	222	99
Total Other Income and Deductions	(49)	(250)	(269)	(480)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	764	542	1,149	1,201
INCOME TAXES	279	227	427	499
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	485	315	722	702
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES (net of income taxes of $90 and $8 for the six months ended June 30, 2002 and 2001, respectively)	--	--	(230)	12
NET INCOME	485	315	492	714
OTHER COMPREHENSIVE INCOME (LOSS) (net of income taxes)				
SFAS 133 Transition Adjustment	--	--	--	44
Cash Flow Hedge Fair Value Adjustment	(21)	(28)	(78)	(43)
Unrealized Gain (Loss) on Marketable Securities, net	(72)	31	(87)	(72)
Total Other Comprehensive Income (Loss)	(93)	3	(165)	(71)
TOTAL COMPREHENSIVE INCOME	$ 392	$ 318	$ 327	$ 643
AVERAGE SHARES OF COMMON STOCK OUTSTANDING - Basic	322	321	322	320
AVERAGE SHARES OF COMMON STOCK OUTSTANDING - Diluted	324	324	324	323
EARNINGS PER AVERAGE COMMON SHARE:				
BASIC:				
Income Before Cumulative Effect of Changes in Accounting Principles	$ 1.50	$ 0.98	$ 2.24	$ 2.19
Cumulative Effect of Changes in Accounting Principles	--	--	(0.71)	0.04
Net Income	$ 1.50	$ 0.98	$ 1.53	$ 2.23
DILUTED:				
Income Before Cumulative Effect of Changes in Accounting Principles	$ 1.50	$ 0.97	$ 2.23	$ 2.17
Cumulative Effect of Changes in Accounting Principles	--	--	(0.71)	0.04
Net Income	$ 1.50	$ 0.97	$ 1.52	$ 2.21
DIVIDENDS PER COMMON SHARE	$ 0.44	$ 0.42	$ 0.88	$ 0.98

See Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(in millions)	Six Months Ended June 30, 2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 492	$ 714
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Depreciation and Amortization, including nuclear fuel	848	939
Cumulative Effect of a Change in Accounting Principle (net of income taxes)	230	(12)
Net Gain on Sale of Investments (net of income taxes)	(199)	--
Provision for Uncollectible Accounts	67	60
Deferred Income Taxes	(10)	7
Deferred Energy Costs	49	7
Equity in Earnings of Unconsolidated Affiliates, net	(22)	(25)
Net Realized Losses on Nuclear Decommissioning Trust Funds	21	24
Other Operating Activities	115	(78)
Changes in Working Capital:		
Accounts Receivable	(259)	68
Inventories	(42)	(12)
Accounts Payable, Accrued Expenses and Other Current Liabilities	342	280
Changes in Receivables and Payables to Unconsolidated Affiliates, net	12	--
Other Current Assets	(6)	(19)
Net Cash Flows provided by Operating Activities	1,638	1,953
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	(1,028)	(937)
Acquisition of Generating Plants	(443)	--
Enterprises Acquisitions, net of cash acquired	--	(39)
Proceeds from the Sale of Investment	285	--
Proceeds from Nuclear Decommissioning Trust Funds	889	621
Investment in Nuclear Decommissioning Trust Funds	(943)	(655)
Note Receivable from Unconsolidated Affiliate	(75)	--
Other Investing Activities	47	12
Net Cash Flows used in Investing Activities	(1,268)	(998)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	701	2,058
Retirement of Long-Term Debt	(697)	(1,153)
Change in Short-Term Debt	110	(949)
Dividends on Common Stock	(280)	(312)
Change in Restricted Cash	(26)	(16)
Proceeds from Employee Stock Plans	60	51
Other Financing Activities	(10)	--
Net Cash Flows used in Financing Activities	(142)	(321)
INCREASE IN CASH AND CASH EQUIVALENTS	228	634
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	485	526
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 713	$ 1,160
SUPPLEMENTAL CASH FLOW INFORMATION		
Noncash Investing and Financing Activities:		
Regulatory Asset Fair Value Adjustment	--	$ 347

See Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in millions)	June 30, 2002	December 31, 2001
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 713	$ 485
Restricted Cash	398	372
Accounts Receivable, net		
Customer	1,978	1,687
Other	196	428
Receivable from Unconsolidated Affiliate	107	44
Inventories, at average cost		
Fossil Fuel	206	222
Materials and Supplies	308	249
Deferred Income Taxes	76	23
Other	354	272
Total Current Assets	4,336	3,782
PROPERTY, PLANT AND EQUIPMENT, NET	14,654	13,781
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets	6,237	6,423
Nuclear Decommissioning Trust Funds	3,060	3,165
Investments	1,658	1,666
Goodwill, net	4,971	5,335
Other	705	708
Total Deferred Debits and Other Assets	16,631	17,297
TOTAL ASSETS	$ 35,621	$ 34,860

See Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in millions)	June 30, 2002	December 31, 2001
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Notes Payable	$ 470	$ 360
Long-Term Debt Due within One Year	1,772	1,406
Accounts Payable	1,164	964
Accrued Expenses	1,339	1,182
Other	527	505
Total Current Liabilities	5,272	4,417
LONG-TERM DEBT	12,591	12,879
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	4,204	4,303
Unamortized Investment Tax Credits	308	316
Nuclear Decommissioning Liability for Retired Plants	1,379	1,353
Pension Obligation	313	334
Non-Pension Postretirement Benefits Obligation	878	847
Spent Nuclear Fuel Obligation	851	843
Other	866	725
Total Deferred Credits and Other Liabilities	8,799	8,721
PREFERRED SECURITIES OF SUBSIDIARIES	613	613
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY		
Common Stock	6,990	6,930
Deferred Compensation	(1)	(2)
Retained Earnings	1,421	1,200
Accumulated Other Comprehensive Income (Loss)	(64)	102
Total Shareholders' Equity	8,346	8,230
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 35,621	$ 34,860

See Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(in millions)	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
OPERATING REVENUES				
Operating Revenues	$1,469	$1,517	$ 2,773	$ 2,921
Operating Revenues from Affiliates	12	13	23	55
Total Operating Revenues	1,481	1,530	2,796	2,976
OPERATING EXPENSES				
Purchased Power	6	1	12	2
Purchased Power from Affiliate	547	585	1,079	1,193
Operating and Maintenance	191	210	386	396
Operating and Maintenance from Affiliates	29	38	71	70
Depreciation and Amortization	133	168	268	334
Taxes Other Than Income	73	69	146	141
Total Operating Expense	979	1,071	1,962	2,136
OPERATING INCOME	502	459	834	840
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(127)	(143)	(252)	(284)
Distributions on Company-Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely the Company's Subordinated Debt Securities	(7)	(7)	(15)	(15)
Interest Income from Affiliates	8	17	16	45
Other, net	6	5	13	14
Total Other Income and Deductions	(120)	(128)	(238)	(240)
INCOME BEFORE INCOME TAXES	382	331	596	600
INCOME TAXES	151	149	236	271
NET INCOME	231	182	360	329
OTHER COMPREHENSIVE INCOME (LOSS) (net of income taxes):				
Cash Flow Hedge Fair Value Adjustment	(14)	--	(16)	--
Unrealized Gain (Loss) on Marketable Securities	(2)	--	(2)	(4)
Total Other Comprehensive Income (Loss)	(16)	--	(18)	(4)
TOTAL COMPREHENSIVE INCOME	$ 215	$ 182	$ 342	$ 325

See Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(in millions)	Six Months Ended June 30, 2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 360	$ 329
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Depreciation and Amortization	268	334
Provision for Uncollectible Accounts	11	18
Deferred Income Taxes	75	38
Other Operating Activities	71	(36)
Changes in Working Capital:		
Accounts Receivable	(158)	(45)
Inventories	--	16
Accounts Payable, Accrued Expenses and Other Current Liabilities	51	320
Changes in Receivables and Payables to Affiliates, net	63	(278)
Other Current Assets	(1)	9
Net Cash Flows provided by Operating Activities	740	705
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	(372)	(459)
Notes Receivable from Affiliate	13	400
Other Investing Activities	7	1
Net Cash Flows used in Investing Activities	(352)	(58)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	701	--
Retirement of Long-Term Debt	(481)	(174)
Dividends on Common Stock	(235)	(148)
Change in Restricted Cash	(32)	--
Other Financing Activities	(10)	--
Net Cash Flows used in Financing Activities	(57)	(322)
INCREASE IN CASH AND CASH EQUIVALENTS	331	325
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	23	141
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 354	$ 466
SUPPLEMENTAL CASH FLOW INFORMATION Noncash Investing and Financing Activities:		
Net Assets Transferred as a result of Restructuring, net of Note Payable	$ --	$ 1,307
Receivable from Parent	$ --	$ 1,062
Regulatory Asset Fair Value Adjustment	$ --	$ 347
Retirement of Treasury Shares	$ 1,344	$ 2,022

See Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in millions)	June 30, 2002	December 31, 2001
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 354	$ 23
Restricted Cash	73	41
Accounts Receivable, net		
Customer	886	745
Other	93	87
Receivables from Affiliates	35	95
Inventories, at average cost	56	56
Deferred Income Taxes	16	52
Other	16	15
Total Current Assets	1,529	1,114
PROPERTY, PLANT AND EQUIPMENT, NET	7,522	7,351
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets	614	667
Investments	54	64
Goodwill, net	4,895	4,902
Notes Receivable from Affiliates	1,301	1,314
Other	283	304
Total Deferred Debits and Other Assets	7,147	7,251
TOTAL ASSETS	$ 16,198	$ 15,716

See Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in millions)	June 30, 2002	December 31, 2001
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due within One Year	$ 848	$ 849
Accounts Payable	184	144
Accrued Expenses	393	374
Payables to Affiliates	272	307
Other	197	212
Total Current Liabilities	1,894	1,886
LONG-TERM DEBT	6,095	5,850
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	1,725	1,671
Unamortized Investment Tax Credits	53	55
Pension Obligation	163	151
Non-Pension Postretirement Benefits Obligation	149	146
Payables to Affiliates	267	297
Other	263	248
Total Deferred Credits and Other Liabilities	2,620	2,568
COMPANY-OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUSTS HOLDING SOLELY THE COMPANY'S SUBORDINATED DEBT SECURITIES	329	329
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY		
Common Stock	1,588	2,048
Preference Stock	7	7
Other Paid-in Capital	4,181	5,057
Receivable from Parent	(875)	(937)
Retained Earnings	382	257
Treasury Stock, at cost	--	(1,344)
Accumulated Other Comprehensive Income (Loss)	(23)	(5)
Total Shareholders' Equity	5,260	5,083
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 16,198	$ 15,716

See Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

(in millions)	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
OPERATING REVENUES				
Operating Revenues	$ 992	$ 903	$ 2,008	$ 1,952
Operating Revenues from Affiliates	3	3	7	5
Total Operating Revenues	995	906	2,015	1,957
OPERATING EXPENSES				
Purchased Power	59	51	107	90
Purchased Power from Affiliate	346	264	649	508
Fuel	53	79	188	284
Operating and Maintenance	123	122	251	251
Operating and Maintenance from Affiliates	8	4	16	7
Depreciation and Amortization	109	99	221	200
Taxes Other Than Income	63	41	122	84
Total Operating Expense	761	660	1,554	1,424
OPERATING INCOME	234	246	461	533
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(92)	(117)	(187)	(219)
Interest Expense from Affiliate	--	(2)	--	(8)
Company-Obligated Mandatorily Redeemable Preferred Securities of a Partnership, which holds Solely Subordinated Debentures of the Company	(2)	(2)	(5)	(5)
Interest Income from Affiliates	--	1	--	1
Other, net	2	3	2	17
Total Other Income and Deductions	(92)	(117)	(190)	(214)
INCOME BEFORE INCOME TAXES	142	129	271	319
INCOME TAXES	49	44	90	112
NET INCOME	93	85	181	207
Preferred Stock Dividends	(2)	(3)	(4)	(5)
NET INCOME ON COMMON STOCK	$ 91	$ 82	$ 177	$ 202
OTHER COMPREHENSIVE INCOME				
Net Income	$ 93	$ 85	$ 181	$ 207
Other Comprehensive Income (Loss) (net of income taxes):				
SFAS 133 Transition Adjustment	--	--	--	40
Cash Flow Hedge Fair Value Adjustment	(6)	8	(4)	(10)
Total Other Comprehensive Income	(6)	8	(4)	30
TOTAL COMPREHENSIVE INCOME	$ 87	$ 93	$ 177	$ 237

See Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(in millions)	Six Months Ended June 30, 2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 181	$ 207
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Depreciation and Amortization	221	200
Provision for Uncollectible Accounts	32	29
Deferred Income Taxes	(19)	13
Deferred Energy Costs	49	7
Other Operating Activities	(81)	(40)
Changes in Working Capital:		
Accounts Receivable	(4)	(19)
Changes in Receivables and Payables to Affiliates, net	34	75
Inventories	14	6
Accounts Payable, Accrued Expenses and Other Current Liabilities	44	22
Other Current Assets	(3)	(73)
Net Cash Flows provided by Operating Activities	468	427
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	(123)	(122)
Other Investing Activities	1	35
Net Cash Flows used in Investing Activities	(122)	(87)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of Long-Term Debt	(207)	(978)
Issuance of Long-Term Debt	--	805
Contribution from Parent	--	53
Change in Short-Term Debt	74	(122)
Dividends on Preferred and Common Stock	(174)	(105)
Change in Restricted Cash	1	(16)
Settlement of Interest Rate Swap Agreements	--	31
Net Cash Flows used in Financing Activities	(306)	(332)
INCREASE IN CASH AND CASH EQUIVALENTS	40	8
Cash Transferred in Restructuring	--	(31)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	32	49
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 72	$ 26
SUPPLEMENTAL CASH FLOW INFORMATION Noncash Investing and Financing Activities:		
Net Assets Transferred as a result of Restructuring, net of Receivable from Affiliates	$ --	$ 1,624
Contribution of Receivable from Parent	$ --	$ 1,983

See Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in millions)	June 30, 2002	December 31, 2001
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 72	$ 32
Restricted Cash	322	323
Accounts Receivable, net		
Customer	261	286
Other	30	33
Receivables from Affiliates	6	8
Inventories, at average cost		
Fossil Fuel	59	72
Materials and Supplies	6	7
Prepaid Taxes	98	1
Other	13	58
Total Current Assets	867	820
PROPERTY, PLANT AND EQUIPMENT, NET	4,098	4,047
DEFERRED DEBITS AND OTHER ASSETS		
Regulatory Assets	5,623	5,756
Investments	22	24
Pension Asset	29	13
Other	78	85
Total Deferred Debits and Other Assets	5,752	5,878
TOTAL ASSETS	$ 10,717	$ 10,745

See Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in millions)	June 30, 2002	December 31, 2001
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Notes Payable	$ 175	$ 101
Payables to Affiliates	190	194
Long-Term Debt Due within One Year	910	548
Accounts Payable	52	54
Accrued Expenses	436	397
Deferred Income Taxes	27	27
Other	33	21
Total Current Liabilities	1,823	1,342
LONG-TERM DEBT	4,869	5,438
DEFERRED CREDITS AND OTHER LIABILITIES		
Deferred Income Taxes	2,927	2,938
Unamortized Investment Tax Credits	26	27
Non-Pension Postretirement Benefits Obligation	263	239
Payables to Affiliates	20	44
Other	120	110
Total Deferred Credits and Other Liabilities	3,356	3,358
COMPANY-OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF A PARTNERSHIP, WHICH HOLDS SOLEY SUBORDINATED DEBENTURES OF THE COMPANY	128	128
MANDATORILY REDEEMABLE PREFERRED STOCK	19	19
COMMITMENTS AND CONTINGENCIES		
SHAREHOLDERS' EQUITY		
Common Stock	1,911	1,912
Receivable from Parent	(1,818)	(1,878)
Preferred Stock	137	137
Retained Earnings	277	270
Accumulated Other Comprehensive Income	15	19
Total Shareholders' Equity	522	460
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 10,717	$ 10,745

See Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2002	2001	2002	2001
OPERATING REVENUES				
Operating Revenues	$ 606	$ 677	$1,175	$ 1,392
Operating Revenues from Affiliates	953	906	1,845	1,819
Total Operating Revenues	1,559	1,583	3,020	3,211
OPERATING EXPENSES				
Purchased Power	634	690	1,186	1,272
Purchased Power from Affiliates	71	31	137	48
Fuel	224	230	433	449
Operating and Maintenance	405	400	833	798
Operating and Maintenance Expense from Affiliates	6	5	11	11
Depreciation and Amortization	65	75	128	167
Taxes Other Than Income	41	39	90	85
Total Operating Expense	1,446	1,470	2,818	2,830
OPERATING INCOME	113	113	202	381
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(10)	(17)	(27)	(35)
Interest Expense from Affiliates	(1)	(9)	(1)	(24)
Equity in Earnings of Unconsolidated Affiliates	9	13	32	39
Other, net	24	14	40	18
Total Other Income and Deductions	22	1	44	(2)
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	135	114	246	379
INCOME TAXES	51	43	96	150
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	84	71	150	229
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	--	--	13	12
NET INCOME	84	71	163	241
OTHER COMPREHENSIVE INCOME (LOSS) (net of income taxes)				
Unrealized Gain (Loss) on Marketable Securities	(74)	31	(83)	(80)
SFAS 133 Transition Adjustment	--	--	--	4
Cash Flow Hedge Fair Value Adjustment	6	(35)	(67)	(36)
Total Other Comprehensive Income (Loss)	(68)	(4)	(150)	(112)
TOTAL COMPREHENSIVE INCOME	$ 16	$ 67	$ 13	$ 129

See Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(in millions)	Six Months Ended June 30, 2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 163	$ 241
Adjustments to Reconcile Net Income to Net Cash Flows Provided by Operating Activities:		
Depreciation and Amortization, including nuclear fuel	312	366
Cumulative Effect of a Change in Accounting Principle (net of income taxes)	(13)	(12)
Provision for Uncollectible Accounts	17	3
Deferred Income Taxes	(4)	(6)
Equity in (Earnings) Losses of Unconsolidated Affiliates	(32)	(39)
Net Realized Losses on Nuclear Decommissioning Trust Funds	21	24
Other Operating Activities	70	(116)
Changes in Working Capital:		
Accounts Receivable	(136)	115
Changes in Receivables and Payables to Affiliates, net	(93)	(161)
Inventories	(54)	(110)
Accounts Payable, Accrued Expenses and Other Current Liabilities	316	156
Other Current Assets	(48)	24
Net Cash Flows provided by Operating Activities	519	485
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital Expenditures	(475)	(301)
Acquisition of Generating Plants	(443)	--
Proceeds from Nuclear Decommissioning Trust Funds	889	621
Investment in Nuclear Decommissioning Trust Funds	(943)	(655)
Note Receivable from Affiliate	(75)	236
Other Investing Activities	(1)	--
Net Cash Flows used in Investing Activities	(1,048)	(99)
CASH FLOWS FROM FINANCING ACTIVITIES		
Change in Intercompany Payable, Affiliate	331	(696)
Issuance of Long-Term Debt	--	752
Retirement of Long-Term Debt	(2)	(2)
Distribution to Member	--	(121)
Net Cash Flows provided by (used in) Financing Activities	329	(67)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(200)	319
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	224	4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 24	$ 323

See Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in millions)	June 30, 2002	December 31, 2001
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 24	$ 224
Accounts Receivable, net		
Customer	503	316
Other	38	150
Receivable from Affiliate	523	444
Inventories, at average cost		
Fossil Fuel	135	105
Materials and Supplies	227	202
Accumulated Deferred Income Taxes	7	--
Other	103	65
Total Current Assets	1,560	1,506
PROPERTY, PLANT AND EQUIPMENT, NET	2,650	2,003
DEFERRED DEBITS AND OTHER ASSETS		
Nuclear Decommissioning Trust Funds	3,060	3,165
Investments	913	859
Notes Receivable from Affiliates	261	291
Deferred Income Taxes	437	297
Other	223	223
Total Deferred Debits and Other Assets	4,894	4,835
TOTAL ASSETS	$ 9,104	$ 8,344

See Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(in millions)	June 30, 2002	December 31, 2001
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due within One Year	$ 6	$ 4
Accounts Payable	788	585
Accounts Payable to Affiliate	16	105
Notes Payable to Affiliate	331	--
Accrued Expenses	416	303
Deferred Income Taxes	--	7
Other	215	171
Total Current Liabilities	1,772	1,175
LONG-TERM DEBT	1,065	1,021
DEFERRED CREDITS AND OTHER LIABILITIES		
Unamortized Investment Tax Credits	230	234
Nuclear Decommissioning Liability for Retired Plants	1,379	1,353
Pension Obligation	102	118
Non-Pension Postretirement Benefits Obligation	396	384
Spent Nuclear Fuel Obligation	851	843
Other	361	280
Total Deferred Credits and Other Liabilities	3,319	3,212
COMMITMENTS AND CONTINGENCIES		
MEMBER'S EQUITY		
Membership Interest	2,316	2,316
Undistributed Earnings	686	523
Accumulated Other Comprehensive Income (Loss)	(54)	97
Total Member's Equity	2,948	2,936
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 9,104	$ 8,344

See Notes to Consolidated Financial Statements

1. BASIS OF PRESENTATION (Exelon, ComEd, PECO and Generation)

The accompanying consolidated financial statements as of June 30, 2002 and for the three and six months then ended are unaudited, but include all adjustments that Exelon Corporation (Exelon), Commonwealth Edison Company (ComEd), PECO Energy Company (PECO) and Exelon Generation Company, LLC (Generation) consider necessary for a fair presentation of their respective financial statements. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2001 consolidated balance sheet data were derived from audited financial statements but do not include all disclosures required by generally accepted accounting principles. Certain prior-year amounts have been reclassified for comparative purposes. These reclassifications had no effect on net income or shareholders' or member's equity. These notes should be read in conjunction with the Notes to Consolidated Financial Statements of Exelon, ComEd and PECO included in or incorporated by reference in Item 8 of their Annual Report on Form 10-K for the year ended December 31, 2001 and the Notes to Consolidated Financial Statements in Generation's Form S-4 registration statement declared effective on April 24, 2002 by the Securities and Exchange Commission (SEC), (Generation's Form S-4). See ITEM 6. Exhibits and Reports on Form 8-K.

2. ADOPTION OF NEW ACCOUNTING PRINCIPLES (Exelon, ComEd, PECO and Generation)

SFAS No. 141 and SFAS No. 142

In 2001, the Financial Accounting Standard Board (FASB) issued Statement of Accounting Standard (SFAS) No. 141, "Business Combinations" (SFAS No. 141), which requires that all business combinations be accounted for under the purchase method of accounting and establishes criteria for the separate recognition of intangible assets acquired in business combinations. SFAS No. 141 is effective for business combinations initiated after June 30, 2001. In addition, SFAS No. 141 requires that unamortized negative goodwill related to pre-July 1, 2001 purchases be recognized as a change in accounting principle concurrent with the adoption of SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142). At December 31, 2001, AmerGen Energy Company, LLC (AmerGen), an equity-method investee of Generation, had $43 million of negative goodwill, net of accumulated amortization, recorded on its balance sheet. Upon AmerGen's adoption of SFAS No. 141 in January 2002, Generation recognized its proportionate share of income of $22 million ($13 million, net of income taxes) as a cumulative effect of a change in accounting principle.

Exelon, ComEd, PECO and Generation adopted SFAS No. 142 as of January 1, 2002. SFAS No. 142 establishes new accounting and reporting standards for goodwill and intangible assets. Other than goodwill, Exelon does not have significant other intangible assets recorded on its consolidated balance sheets. Under SFAS No. 142, goodwill is no longer subject to amortization, however, goodwill is subject to an assessment for impairment using a two-step fair value based test, the first step of which must be performed at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired. The first step compares the fair value of a reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step compares the carrying amount of the goodwill to the fair value of the goodwill. If the fair value of goodwill is less than the carrying amount, an impairment loss is reported as a reduction to goodwill and a charge to operating expense, except at the transition date, when the loss is reflected as a cumulative effect of a change in accounting principle.

As of December 31, 2001, Exelon's Consolidated Balance Sheets reflected approximately $5.3 billion in goodwill net of accumulated amortization, including $4.9 billion of net goodwill related to the October 20, 2000 merger of Unicom Corporation (Unicom), the former parent company of ComEd, and PECO (Merger) recorded on ComEd's Consolidated Balance Sheets, with the remainder related to acquisitions by Exelon Enterprises Company, LLC (Enterprises). The first step of the transitional impairment analysis indicated that ComEd's goodwill was not impaired but that an impairment did exist with respect to goodwill recorded in Enterprises' reporting units. Exelon's infrastructure services business (InfraSource), the energy services business (Exelon Services) and the competitive retail energy sales business (Exelon Energy) were determined to be those reporting units of Enterprises that had goodwill allocated to them. The second step of the analysis, which compared the fair value of each of Enterprises' reporting units' goodwill to the carrying value at December 31, 2001, indicated a total goodwill impairment of $357 million ($243 million, net of income taxes and minority interest). The fair value of the Enterprises' reporting units was determined using discounted cash flow models reflecting the expected range of future cash flow outcomes related to each of the Enterprises reporting units over the life of the model. These cash flows were discounted to 2002 using a risk-adjusted discount rate. The impairment was recorded as a cumulative effect of a change in accounting principle in the first quarter of 2002.

The changes in the carrying amount of goodwill by reportable segment (see Note 6 for further discussion of reportable segments) for the six months ended June 30, 2002 are as follows:

	Energy Delivery	Enterprises	Total
Balance as of January 1, 2002	$ 4,902	$ 433	$ 5,335
Impairment losses	--	(357)	(357)
Settlement of pre-merger income tax contingency	(7)	--	(7)
Balance as of June 30, 2002	$ 4,895	$ 76	$ 4,971

The June 30, 2002, Energy Delivery goodwill relates to ComEd and the remaining Enterprises goodwill relates to the InfraSource and Exelon Services reporting units. Consistent with SFAS No. 142, the remaining goodwill will be reviewed for impairment on an annual basis or more frequently if significant events occur that could indicate an impairment exists.

The components of the net transitional impairment loss recognized in the first quarter of 2002 as a cumulative effect of a change in accounting principle are as follows:

Exelon		
Enterprises goodwill impairment (net of income taxes of $103 million)	$	(254)
Minority interest (net of income taxes of $4 million)		11
Elimination of AmerGen negative goodwill (net of income taxes of $9 million)		13
Total cumulative effect of a change in accounting principle	$	(230)

Generation		
Elimination of AmerGen negative goodwill (net of income taxes of $9 million) recorded as cumulative effect of a change in accounting principle	$	13

The following tables set forth Exelon's net income and earnings per common share and ComEd's net income for the three and six months ended June 30, 2002 and 2001, respectively, adjusted to exclude 2001 amortization expense related to goodwill that is no longer being amortized.

Exelon

	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
Reported income before cumulative effect of changes in accounting principles	$ 485	$ 315	$ 722	$ 702
Cumulative effect of changes in accounting principles	--	--	(230)	12
Reported net income	485	315	492	714
Goodwill amortization	--	38	--	77
Adjusted net income	$ 485	$ 353	$ 492	$ 791
Basic earnings per common share:				
Reported income before cumulative effect of changes in accounting principles	$ 1.50	$ 0.98	$ 2.24	$ 2.19
Cumulative effect of changes in accounting principles	--	--	(0.71)	0.04
Reported net income	1.50	0.98	1.53	2.23
Goodwill amortization	--	0.12	--	0.24
Adjusted net income	$ 1.50	$ 1.10	$ 1.53	$ 2.47
Diluted earnings per common share:				
Reported income before cumulative effect of changes in accounting principles	$ 1.50	$ 0.97	$ 2.23	$ 2.17
Cumulative effect of changes in accounting principles	--	--	(0.71)	0.04
Reported net income	1.50	0.97	1.52	2.21
Goodwill amortization	--	0.12	--	0.24
Adjusted net income	$ 1.50	$ 1.09	$ 1.52	$ 2.45

ComEd

	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001
Reported net income	$ 231	$ 182	$ 360	$ 329
Goodwill amortization	--	32	--	64
Adjusted net income	$ 231	$ 214	$ 360	$ 393

Generation

The cessation of the amortization of negative goodwill of AmerGen on January 1, 2002 did not have a material impact on Generation's reported net income for the three or six months ended June 30, 2002.

EITF Issue 02-3

Exelon and Generation early adopted the provision of Emerging Issues Task Force (EITF) Issue 02-3 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) issued by the FASB EITF in June 2002 that requires revenues and energy costs related to energy trading contracts to be presented on a net basis in the income statement. Prior to the second quarter of 2002, revenues from trading activity were presented in Revenue and the energy costs related to energy trading were presented as either Purchased Power or Fuel expense on Exelon and Generation's Consolidated Statements of Income. For comparative purposes, energy costs related to energy trading have been reclassified in prior periods to revenue to conform with the net basis of presentation required by EITF 02-3. For the three and six months ended June 30, 2001, $30 million of purchased power expense and $5 million of fuel expense was reclassified and reflected as a reduction to revenue. The three months ended March 31, 2002 included $504 million of purchased power expense and $9 million of fuel expense that has been reclassified and reflected as a reduction to revenue in the six months ended June 30, 2002.

SFAS No. 144

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144). Exelon, ComEd, PECO and Generation adopted SFAS No. 144 on January 1, 2002. SFAS No. 144 establishes accounting and reporting standards for both the impairment and disposal of long-lived assets. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001 and its provisions are generally applied prospectively. The adoption of this statement had no effect on Exelon's reported financial positions, results of operations or cash flows.

SFAS No. 133

SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133) applies to all derivative instruments and requires that such instruments be recorded on the balance sheet either as an asset or a liability measured at their fair value through earnings, with special accounting permitted for certain qualifying hedges. On January 1, 2001, Exelon, ComEd, PECO, and Generation adopted SFAS No. 133. Generation recognized a non-cash gain of $12 million, net of income taxes, in earnings and deferred a non-cash gain of $4 million, net of income taxes, in accumulated other comprehensive income and PECO deferred a non-cash gain of $40 million, net of income taxes, in accumulated other comprehensive income.

3. ACQUISITIONS AND DISPOSITIONS (Exelon and Generation)

Acquisition of Generating Plants from TXU

On April 25, 2002, Generation acquired two natural-gas and oil-fired plants from TXU Corp. (TXU) for an aggregate purchase price of $443 million. The purchase included the 893-megawatt Mountain Creek Steam Electric Station in Dallas and the 1,441-megawatt Handley Steam Electric Station in Fort Worth. The transaction included a power purchase agreement for TXU to purchase power during the months of May through September from 2002 through 2006. During the periods covered by the power purchase agreement, TXU will make fixed capacity payments and will provide fuel to Exelon in return for exclusive rights to the energy and capacity of the generation plants. Substantially all of the purchase price has been allocated to property, plant, and equipment pending final valuation of plant assets.

Sale of AT&T Wireless

On April 1, 2002, Enterprises sold its 49% interest in AT&T Wireless PCS of Philadelphia, LLC to a subsidiary of AT&T Wireless Services for $285 million in cash. Enterprises recorded an after-tax gain of $116 million in other, net on the $84 million investment, which was reflected in Deferred Debits and Other Assets on Exelon's Consolidated Balance Sheets.

Sithe New England Holdings, LLC Acquisition

On June 26, 2002, Generation agreed to purchase Sithe New England Holdings, LLC, (Sithe New England) a subsidiary of Sithe Energies Inc. (Sithe), and related power marketing operations in exchange for a $543 million note plus the assumption of non-recourse debt, estimated to be approximately $1.2 billion at the transaction closing date. The parties are seeking Federal Energy Regulatory Commission (FERC) and other required approvals of the purchase by October 31, 2002. Exelon has negotiated closing conditions that allow Exelon to terminate the purchase if the conditions are not satisfied. If approved, and if the closing conditions are satisfied, the transaction could be completed in November 2002.

The purchase involves approximately 4,471 MWs of generation capacity, consisting of 2,050 MWs in operation and 2,421 MWs under construction, which will increase Generation's net assets by approximately $1.7 billion when the transaction closes. Sithe New England's generation facilities are located primarily in Massachusetts, but are also located in Maine.

Generation is a 49.9% owner of Sithe and accounts for the investment as an unconsolidated equity investment. The Sithe New England purchase will not affect the accounting for Sithe as an equity investment. Additionally, Generation is subject to a Put and Call Agreement (PCA) that gives Generation the right to purchase (Call) the remaining 50.1% of Sithe, and gives the other Sithe shareholders the right to sell (Put) their interest to Generation. If the Put option is exercised, Generation has the obligation to complete the purchase. The PCA provides that the Put and Call options become exercisable as of December 18, 2002. The Sithe New England purchase is a separate transaction from the PCA that is intended to enable Generation to acquire only the Sithe assets that fit Generation's strategy, accelerate the realization of synergies, and reduce the amount of debt needed to finance the transaction.

See ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Exelon Corporation - for further discussion of the PCA.

4. REGULATORY ISSUES (Exelon, ComEd and PECO)

On April 1, 2002, the Illinois Commerce Commission (ICC) issued an interim order in ComEd's Delivery Services Rate Case. The interim order is subject to an audit of test year expenditures that is anticipated to be completed by the end of 2002 with a final order to be issued in 2003. The order sets new delivery rates for residential customers choosing a new retail electric supplier. The new rates became effective May 1, 2002 when residential customers were eligible to choose their supplier of electricity. Traditional bundled rates paid by customers that retain ComEd as their electricity supplier are not affected by this order. Bundled rates will remain frozen through 2006, as a result of the June 6, 2002 amendments to the Illinois

Restructuring Act that extended the freeze on bundled rates for an additional two years. Delivery service rates for non-residential customers are not affected by the order. The potential revenue impact of the interim order is not expected to be material in 2002.

As permitted by the Pennsylvania Electric Competition Act, the Pennsylvania Department of Revenue has calculated a 2002 Revenue Neutral Reconciliation (RNR) adjustment to the gross receipts tax rate in order to neutralize the impact of electric restructuring on its tax revenues. In January 2002, the Pennsylvania Public Utility Commission (PUC) approved the RNR adjustment to the gross receipts tax rate collected from customers. Effective January 1, 2002, PECO implemented the change in the gross receipts tax rate. The RNR adjustment is under appeal. The RNR adjustment increases the gross receipts tax rate, which will increase PECO's annual revenues and tax obligations by approximately $50 million in 2002.

5. EARNINGS PER SHARE (Exelon)

Diluted earnings per share are calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding under Exelon's stock option plans considered to be common stock equivalents. The following table shows the effect of these stock options on the weighted average number of shares outstanding used in calculating diluted earnings per share (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2002	2001	2002	2001
Average common shares outstanding	322	321	322	320
Assumed exercise of stock options	2	3	2	3
Average diluted common shares outstanding	324	324	324	323

Stock options not included in average common shares used in calculating diluted earnings per share due to their antidilutive effect were three million for the three and six months ended June 30, 2002 and one million for the three and six months ended June 30, 2001.

6. SEGMENT INFORMATION (Exelon)

Exelon operates in three business segments: energy delivery, generation and enterprises. Energy delivery consists of the operations of ComEd and PECO. Beginning in 2002, Exelon evaluates the performance of its business segments on the basis of net income. Exelon's segment information for the three months and six months ended June 30, 2002 as compared to the same periods in 2001 and at June 30, 2002 and December 31, 2001 are as follows:

Three Months Ended June 30, 2002 as compared to Three Months Ended June 30, 2001

	Energy Delivery	Generation	Enterprises	Corporate and Intersegment Eliminations	Consolidated
Revenues:					
2002	$ 2,476	$ 1,559	$ 476	$ (992)	$ 3,519
2001	2,436	1,583	546	(949)	3,616
Intersegment Revenues:					
2002	$ 15	$ 953	$ 24	$ (992)	$ --
2001	16	906	27	(949)	--
Net Income:					
2002	$ 322	$ 84	$ 83	$ (4)	$ 485
2001	264	71	(5)	(15)	315

Six Months Ended June 30, 2002 as compared to Six Months Ended June 30, 2001

	Energy Delivery	Generation	Enterprises	Corporate and Intersegment Eliminations	Consolidated
Revenues:					
2002	$ 4,811	$ 3,020	$ 966	$(1,921)	$ 6,876
2001	4,933	3,211	1,213	(1,918)	7,439
Intersegment Revenues:					
2002	$ 29	$ 1,845	$ 47	$(1,921)	$ --
2001	59	1,819	40	(1,918)	--
Net Income:					
2002	$ 538	$ 163	$ (188)	$ (21)	$ 492
2001	530	241	(30)	(27)	714
Total Assets:					
June 30, 2002	$26,915	$ 9,104	$ 1,290	$(1,688)	$ 35,621
December 31, 2001	26,461	8,344	1,790	(1,735)	34,860

7. FAIR VALUE OF FINANCIAL ASSETS AND LIABILITIES (Exelon, ComEd, PECO and Generation)

During the three and six months ended June 30, 2002 and 2001, Exelon recorded net gains/(losses) in other comprehensive income relating to mark-to-market (MTM) adjustments of contracts designated as cash flow hedges as follows:

	ComEd	PECO	Generation	Enterprises	Exelon
Three months ended June 30, 2002	$(13)	$ (7)	$ 15	$ (3)	$ (8)
Three months ended June 30, 2001	--	15	(61)	(2)	(48)
Six months ended June 30, 2002	(6)	(1)	(107)	14	(100)
Six months ended June 30, 2001	--	8	(62)	2	(52)

During the three months ended June 30, 2002 and 2001, and the six months ended June 30, 2002 and 2001, Generation recognized net MTM gains on non-trading energy derivative contracts not designated as cash flow hedges, in operating revenues as follows:

	2002	2001
Three months ended June 30,	$ 4	$ 5
Six months ended June 30,	10	22

During the three months ended June 30, 2002 and 2001 and the six months ended June 30, 2002 and 2001, no amounts were reclassified from accumulated other comprehensive income into earnings as a result of forecasted energy commodity transactions no longer being probable.

During the three months ended June 30, 2002 and 2001, and the six months ended June 30, 2002 and 2001, Generation recognized net MTM losses on energy trading contracts, in operating revenues as follows:

	2002	2001
Three months ended June 30,	$ (9)	$ (6)
Six months ended June 30,	(13)	(6)

During the three months ended June 30, 2002 and 2001 and the six months ended June 30, 2002 and 2001, PECO reclassified other income in the Consolidated Statements of Income and Comprehensive Income, as a result of the discontinuance of cash flow hedges related to certain forecasted financing transactions that were no longer probable of occurring as follows:

	2002	2001
Three months ended June 30,	$ --	$ --
Six months ended June 30,	--	6

As of June 30, 2002, deferred net gains on derivative instruments accumulated in other comprehensive income are expected to be reclassified to earnings during the next twelve months are as follows:

	ComEd	PECO	Generation	Enterprises	Exelon
Gains Expected to be Reclassified	$ 1	$ 15	$ --	$ 2	$ 18

Amounts in accumulated other comprehensive income related to interest rate cash flow hedges are reclassified into earnings when the forecasted interest payment occurs. Amounts in accumulated other comprehensive income related to energy commodity cash flows are reclassified into earnings when the forecasted purchase or sale of the energy commodity occurs.

Generation classifies investments in the trust accounts for decommissioning nuclear plants as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in these trust accounts.

	June 30, 2002			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Equity securities	$ 1,677	$ 115	$ (406)	$ 1,386
Debt securities				
Government obligations	994	39	(1)	1,032
Other debt securities	641	18	(17)	642
Total debt securities	1,635	57	(18)	1,674
Total available-for-sale securities	$ 3,312	$ 172	$ (424)	$ 3,060

Unrealized gains and losses are recognized in Accumulated Depreciation and Accumulated Other Comprehensive Income in Generation's Consolidated Balance Sheet.

For the three months ended June 30, 2002, proceeds from the sale of decommissioning trust investments and gross realized gains and losses on those sales were $309 million, $13 million and $24 million, respectively. For the six months ended June 30, 2002, proceeds from the sale of decommissioning trust investments and gross realized gains and losses on those sales were $889 million, $31 million and $56 million, respectively.

Net realized losses of $4 million were recognized in Accumulated Depreciation in Generation's Consolidated Balance Sheets at June 30, 2002 and $21 million of net realized losses were recognized in Other Income and Deductions in Generation's Consolidated Statements of Income and Comprehensive Income for the six months ended June 30, 2002. The available-for-sale securities held at June 30, 2002 have an average maturity of eight to ten years. The cost of these securities was determined on the basis of specific identification.

8. COMMITMENTS AND CONTINGENCIES (Exelon, ComEd, PECO and Generation)

For information regarding capital commitments, nuclear decommissioning and spent fuel storage, see the Commitments and Contingencies Note in the Consolidated Financial Statements of Exelon, ComEd and PECO for the year ended December 31, 2001 and Generation's S-4 dated April 24, 2002.

Environmental Liabilities

Exelon has identified 72 sites where former manufactured gas plant (MGP) activities have or may have resulted in actual site contamination. As of June 30, 2002, Exelon had accrued $139 million for environmental investigation and remediation costs that currently can be reasonably estimated, including $115 million for MGP investigation and remediation.

ComEd had accrued $96 million (discounted) as of June 30, 2002, for environmental investigation and remediation costs that currently can be reasonably estimated. This reserve included $90 million for MGP investigation and remediation. ComEd is currently experiencing delays in the ongoing remediation of an MGP site in Oak Park, Illinois, and is evaluating the impact of those delays on the cost to complete the project. The impact of the delays is currently uncertain, but could increase the environmental reserve in the future.

PECO had accrued $34 million (undiscounted) as of June 30, 2002, for environmental investigation and remediation costs that currently can be reasonably estimated, including $25 million for MGP investigation and remediation.

Generation had accrued $9 million (undiscounted) as of June 30, 2002, for environmental investigation and remediation cost, none of which relates to MGP investigation and remediation.

Exelon, ComEd, PECO and Generation cannot predict the extent to which they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by environmental agencies or others, or whether such costs may be recoverable from third parties.

Energy Commitments

Exelon and Generation had long-term commitments relating to the net purchase and sale of energy, capacity and transmission rights from unaffiliated utilities, including Midwest Generation LLC (Midwest Generation), and others, including AmerGen, as expressed in the following table:

	Net Capacity Purchases (1)	Power Only Sales	Power Only Purchases from AmerGen	Power Only Purchases from Non-Affiliates	Transmission Rights Purchases
2002	$ 634	$ 2,111	$ 127	$ 1,659	$ 72
2003	692	1,491	247	588	108
2004	859	822	301	200	89
2005	389	244	227	78	83
2006	352	120	227	66	2
Thereafter	4,120	23	2,045	272	--
Total	$ 7,046	$ 4,811	$ 3,174	$ 2,863	$ 354

(1) Net Capacity Purchases includes Midwest Generation commitments as of July 1, 2002. On July 1, 2002, Generation notified Midwest Generation of the exercise of its call options under the existing Coal Generation Purchase Power Agreement. Generation exercised options on 1,265 MWs of capacity and did not exercise options on 2,684 MWs of capacity. In 2003, Generation will take 1,696 MWs of non-option capacity and 1,265 MWs of option capacity under the existing contract. Net Capacity Purchases also includes capacity sales to TXU under the purchase power agreement entered into in connection with the purchase of two generating plants in April 2002, which states that TXU will purchase the plant output from May through September from 2002 through 2006. The combined capacity of the two plants is 2,334 MWs.

In connection with the 2001 corporate restructuring, ComEd entered into a purchase power agreement (PPA) with Generation. Under the terms of the PPA, Generation has agreed to supply all of ComEd's load requirements through 2004. Prices for this energy vary depending upon the time of day and month of delivery. During 2005 and 2006, ComEd's PPA is a partial requirements agreement under which ComEd will purchase all of its required energy and capacity from Generation, up to the available capacity of the nuclear generating plants formerly owned by ComEd and transferred to Generation. Under the terms of the PPA, Generation is responsible for obtaining any required transmission service. The PPA also specifies that prior to 2005, ComEd and Generation will jointly determine and agree on a market-based price for energy delivered under the PPA for 2005 and 2006. In the event that the parties cannot agree to market-based prices for 2005 and 2006 prior to July 1, 2004, ComEd has the option of terminating the PPA effective December 31, 2004. ComEd will obtain any additional supply required from market sources in 2005 and 2006, and subsequent to 2006, will obtain all of its supply from market sources, which could include Generation.

In connection with the 2001 corporate restructuring, PECO entered into a PPA with Generation. Under the terms of the PPA, PECO obtains substantially all of its electric supply from Generation through 2010. Also, under the restructuring, PECO assigned its rights and obligations under various PPAs and fuel supply agreements to Generation. Generation supplies power to PECO from the transferred generation assets, assigned PPAs and other market sources.

Under terms of the 2001 corporate restructuring, ComEd remits to Generation any amounts collected from customers for nuclear decommissioning. Under an agreement effective September 2001, PECO remits to Generation any amounts collected from customers for nuclear decommissioning.

Litigation

Exelon

Securities Litigation. Between May 8 and June 14, 2002, a total of six nearly identical class action lawsuits were filed in the Federal District Court in Chicago asserting securities claims on behalf of Exelon investors during April to September 2001. The complaints allege that Exelon violated Federal securities laws by issuing a series of materially false and misleading statements relating to its 2001 earnings expectations during the Class Period. On May 30 and July 2, 2002, the Court granted Exelon's agreed-upon motions to consolidate the pending cases into one lawsuit, and stayed discovery indefinitely. A lead plaintiff has not been selected. Exelon believes the lawsuit is without merit and is vigorously contesting this matter.

ComEd

Chicago Franchise. In March 1999, ComEd reached a settlement agreement with the City of Chicago (Chicago) to end the arbitration proceeding between ComEd and Chicago regarding the January 1, 1992 franchise agreement. As part of the settlement agreement, ComEd and Chicago agreed to a revised combination of ongoing work under the franchise agreement and new initiatives that will result in defined transmission and distribution expenditures by ComEd to improve electric services in Chicago. The settlement agreement provides that ComEd would be subject to liquidated damages if the projects are not completed by various dates, unless it was prevented from doing so by events beyond its reasonable control. In addition, ComEd and Chicago established an Energy Reliability and Capacity Account, into which ComEd deposited $25 million during each of the years 1999 through 2001 and has conditionally agreed to deposit $25 million at the end of 2002, to help ensure an adequate and reliable electric supply for Chicago.

FERC Municipal Request for Refund. Three of ComEd's wholesale municipal customers filed a complaint and request for refund with the FERC alleging that ComEd failed to properly adjust its rates, as provided for under the terms of the electric service contracts with the municipal customers and to track certain refunds made to ComEd's retail customers in the years 1992 through 1994. In the third quarter of 1998, FERC granted the complaint and directed that refunds be made, with interest. ComEd filed a request for rehearing. On April 30, 2001, FERC issued an order granting rehearing in which it determined that its 1998 order had been erroneous and that no refunds were due from ComEd to the municipal customers. On June 29, 2001, FERC denied the customers' requests for rehearing of the order granting rehearing. In August 2001, each of the three wholesale municipal customers appealed the April 30, 2001 FERC order to the Federal circuit court, which consolidated the appeals for the purposes of briefing and decision. In November 2001, the court suspended briefing pending court-initiated settlement discussions.

Retail Rate Law. In 1996, several developers of non-utility generating facilities filed litigation against various Illinois officials claiming that the enforcement against those facilities of an amendment to Illinois law removing the entitlement of those facilities to state-subsidized payments for electricity sold to ComEd after March 15, 1996 violated their rights under the Federal and state constitutions. The developers also filed suit against ComEd for a declaratory judgment that their rights under their contracts with ComEd were not affected by the amendment. On August 4, 1999, the Illinois Appellate Court held that the developers' claims against the state were premature, and the Illinois Supreme Court denied leave to appeal that ruling. Developers of both facilities have since filed amended complaints repeating their allegations that ComEd breached the contracts in question and requesting damages for such breach reflecting the state-subsidized rate to which the developers claim they were entitled under their contracts. These matters are in the discovery phase. Certain of the plaintiffs have produced an expert report claiming approximately $175 million in damages, a quantification ComEd vigorously disputes. Virtually all parties have filed motions for summary judgment. ComEd is contesting each case and has filed its motion for summary judgment arguing that, as a matter of law, it did not breach any of the contracts.

Service Interruptions. In August 1999, three class action lawsuits were filed against ComEd, and subsequently consolidated, in the Circuit Court of Cook County, Illinois seeking damages for personal injuries, property damage and economic losses related to a series of service interruptions that occurred in the summer of 1999. The combined effect of these interruptions resulted in over 168,000 customers losing service for more than four hours. Conditional class certification was approved by the court for the sole purpose of exploring settlement talks. ComEd filed a motion to dismiss the complaints. On April 24, 2001, the court dismissed four of the five counts of the consolidated complaint without prejudice and the sole remaining count was dismissed in part. On June 1, 2001, the plaintiffs filed a second amended consolidated complaint and ComEd has filed an answer. A portion of any settlement or verdict may be covered by insurance; discussions with the carrier are ongoing.

Enron. As a result of Enron Corp.'s bankruptcy proceeding, ComEd has potential monetary exposure for 366 of its customer accounts that were served by Enron Energy Services (EES) as a billing agent. EES has rejected its contracts with these accounts, with the exception of approximately 100 accounts for which EES retains its billing agency. ComEd is working to ensure that customers know what amounts are owed to ComEd on accounts for which EES has been removed as billing agent, and has obtained updated billing addresses for these accounts. With regard to the accounts for which EES retains its billing agency, ComEd's total amount outstanding is not material. Because that amount is owed to ComEd by individual customers, it is not part of the bankrupt Enron's estate. The ICC has rescinded EES's authority to act as an alternative retail energy supplier in Illinois. However, EES never served as a supplier, as opposed to a billing agent, to any of ComEd's retail accounts.

ComEd and Generation

Godley Park District Litigation. On April 18, 2001, the Godley Park District filed suit in Will County Circuit Court against ComEd and Generation alleging that oil spills at Braidwood Station have contaminated the Park District's water supply. The complaint sought actual damages, punitive damages of $100 million and statutory penalties. The court dismissed all counts seeking punitive damages and statutory penalties, and the plaintiff has filed an amended complaint before the court. The amended complaint added counts under the Illinois Public Utility Act (PUA), which provides for statutory penalties and allows recovery of attorneys fees. On

April 20, 2002, the Court denied ComEd and Generation's motion to dismiss the additional counts under the PUA. ComEd and Generation are contesting the liability and damages sought by the plaintiff.

Generation

Cotter Corporation Litigation. During 1989 and 1991, actions were brought in Federal and state courts in Colorado against ComEd and its subsidiary, Cotter Corporation (Cotter), seeking unspecified damages and injunctive relief based on allegations that Cotter permitted radioactive and other hazardous material to be released from its mill into areas owned or occupied by the plaintiffs, resulting in property damage and potential adverse health effects. In 1994, a Federal jury returned nominal dollar verdicts against Cotter on eight plaintiffs' claims in the 1989 cases, which verdicts were upheld on appeal. The remaining claims in the 1989 actions were settled or dismissed. In 1998, a jury verdict was rendered against Cotter in favor of 14 of the plaintiffs in the 1991 cases, totaling approximately $6 million in compensatory and punitive damages, interest and medical monitoring. On appeal, the Tenth Circuit Court of Appeals reversed the jury verdict, and remanded the case for new trial. These plaintiffs' cases were consolidated with the remaining 26 plaintiffs' cases, which had not been tried. The consolidated trial was completed on June 28, 2001. The jury returned a verdict against Cotter and awarded $16.3 million in various damages. On November 20, 2001, the District Court entered an amended final judgment that included an award of both pre-judgment and post-judgment interests, costs, and medical monitoring expenses that total $43.3 million. This matter is being appealed by Cotter in the Tenth Circuit Court of Appeals. Cotter will vigorously contest the award.

In November 2000, another trial involving a separate sub-group of 13 plaintiffs, seeking $19 million in damages plus interest was completed in federal district court in Denver. The jury awarded nominal damages of $42,500 to 11 of 13 plaintiffs, but awarded no damages for any personal injury or health claims, other than requiring Cotter to perform periodic medical monitoring at minimal cost. Cotter and the plaintiffs both appealed the verdict to the Tenth Circuit Court of Appeals.

On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability incurred by Cotter as a result of these actions, as well as any liability arising in connection with the West Lake Landfill discussed in the next paragraph. In connection with Exelon's 2001 corporate restructuring, the responsibility to indemnify Cotter for any liability related to these matters was transferred by ComEd to Generation.

The United States Environmental Protection Agency (EPA) has advised Cotter that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. Cotter is alleged to have disposed of approximately 39,000 tons of soils mixed with 8,700 tons of leached barium sulfate at the site. Cotter, along with three other companies identified by the EPA as potentially responsible parties (PRPs), is reviewing a draft feasibility study that recommends capping the site. The PRPs are also engaged in discussions with the State of Missouri and the EPA. The estimated costs of remediation for the site are $10 to $15 million. Once a final feasibility study is complete and a remedy selected, it is expected that the PRPs will agree on an allocation of responsibility for the costs. Until an agreement is reached, Exelon cannot predict its share of the costs.

Real Estate Tax Appeals. Generation is involved in tax appeals regarding a number of its nuclear facilities, Limerick Generating Station (Montgomery County, PA), Peach Bottom Atomic Power Station (York County, PA), Quad Cities Station (Rock Island County, IL), and one of its fossil facilities, Eddystone (Delaware County, PA). Generation is also involved in the tax appeal for Three Mile Island (Dauphin County, PA) through AmerGen. Generation does not believe the outcome of these matters will have a material adverse effect on Generation's results of operations or financial condition.

General

Exelon, ComEd, PECO and Generation are involved in various other litigation matters. The ultimate outcome of such matters, as well as the matters discussed above, while uncertain, are not expected to have a material adverse effect on its respective financial condition or results of operations.

9. MERGER-RELATED COSTS (Exelon, ComEd, PECO and Generation)

In association with the Merger, Exelon recorded certain reserves for restructuring costs. The reserves associated with PECO were charged to expense, while the reserves associated with Unicom were recorded as part of the application of purchase accounting and did not affect results of operations.

Merger-related costs charged to expense in 2000 were $276 million, consisting of $124 million for PECO employee costs and $152 million of direct incremental costs. Direct incremental costs represent expenses directly associated with completing the Merger, including professional fees, regulatory approval and settlement costs, and settlement of compensation arrangements. Employee costs represent estimated severance costs and pension and postretirement benefits provided under Exelon's merger separation plans for eligible employees who are expected to be involuntarily terminated before December 2002 due to integration activities of the merged companies.

The purchase price allocation as of December 31, 2000 included a liability of $307 million for Unicom employee costs and liabilities of approximately $39 million for estimated costs of exiting various business activities of former Unicom activities that were not compatible with the strategic business direction of Exelon.

During 2001, Exelon finalized its plans for consolidation of functions, including negotiation of an agreement with the International Brotherhood of Electrical Workers Local 15 regarding severance benefits to union employees and recorded adjustments to the purchase price allocation as follows:

	Original Estimate	2001 Adjustments	Adjusted Liabilities
Employee severance payments	$ 128	$ 33	$ 161 (a)
Relocation and other benefits	21	9	30 (a)
Employee severance payments and relocation and other benefits	149	42	191
Actuarially determined pension and postretirement costs	158	(11)	147 (b)
Total Unicom - Employee Cost	$ 307	$ 31	$ 338

(a) The increase is a result of the identification in 2001 of additional positions to be eliminated.
(b) The reduction results from lower estimated pension and post retirement welfare benefits reflecting revised actuarial estimates.

The following table provides a reconciliation of the reserve for employee severance and relocation costs associated with the merger:

Employee severance and relocation reserve as of October 20, 2000	$ 149
Additional reserve	42
Adjusted employee severance and relocation reserve	191
Payments to employees (October 2000-March 2002)	(92)
Payments to employees (April 2002-June 2002)	(33)
Employee severance and relocation reserve as of June 30, 2002	$ 66

Additional employee severance costs of $48 million primarily related to PECO employees were charged to expense in 2001. Exelon anticipates that a total of $281 million of employee costs will be funded from pension and postretirement benefit plans.

As part of the January 2001 corporate restructuring, portions of the employee severance and restructuring reserve were transferred from ComEd to Generation, Enterprises and Exelon Business Services Company (BSC). Approximately $37 million and $15 million of the employee severance and relocation reserve as of June 30, 2002 relates to ComEd and Generation, respectively, and is reflected on the Consolidated Balance Sheets of those entities.

Approximately 3,300 Unicom and PECO positions have been identified to be eliminated as a result of the merger. Exelon has terminated 2,255 employees as of June 30, 2002 of which 510 were terminated in the second quarter of 2002. The remaining positions are expected to be eliminated by the end of 2002.

10. LONG-TERM DEBT (Exelon and ComEd)

On June 13, 2002, ComEd issued $200 million of 6.15% First Mortgage Bonds, due March 15, 2012. The $200 million bond issuance was a refinancing of the $200 million of 8.5% First Mortgage Bonds redeemed on July 15, 2002 at a redemption price of 103.915% of the principal amount.

In connection with the issuance of the $200 million of First Mortgage Bonds, ComEd settled a forward starting interest rate swap in the notional amount of $75 million resulting in a $1 million loss recorded in other comprehensive income, which is being amortized over the expected remaining life of the related debt.

On April 15, 2002, ComEd issued $100 million of Illinois Development Finance Authority floating-rate Pollution Control Revenue Refunding Bonds, Series 2002. The $100 million bond issuance was used to redeem $100 million of 7.25% Illinois Development Finance Authority Pollution Control Revenue Refunding Bonds, Series 1991.

On March 13, 2002, ComEd issued $400 million of 6.15% First Mortgage Bonds, due March 15, 2012. This $400 million bond issuance refinanced other First Mortgage Bonds. In connection with the issuance of $400 million of First Mortgage Bonds, ComEd settled forward starting interest rate swaps in the aggregate notional amount of $375 million resulting in a $9 million loss recorded in other comprehensive income, which is being amortized over the expected remaining life of the related debt.

On March 21, 2002, ComEd redeemed $200 million of 8.625% First Mortgage Bonds at the redemption price of 103.84% of the principal amount. These bonds had a maturity date of February 1, 2022.

During the six months ended June 30, 2002, ComEd recorded prepayment premiums of $9 million, partially offset by net unamortized premiums, discounts and debt issuance expenses of $2 million, associated with the early retirement of debt in 2002 that have been deferred by ComEd in regulatory assets and will be amortized to interest expense over the life of the related new debt issuance consistent with regulatory recovery.

11. SALE OF ACCOUNTS RECEIVABLE (Exelon and PECO)

PECO is party to an agreement, which expires in November 2005, with a financial institution under which it can sell or finance with limited recourse an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable. As of June 30, 2002, PECO had sold a $225 million interest in accounts receivable, consisting of a $170 million interest in accounts receivable that PECO accounted for as a sale under SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities, a Replacement of FASB Statement No. 125" and a $55 million interest in special-agreement accounts receivable which were accounted for as a long-term note payable. PECO retains the servicing responsibility for these receivables. The agreement requires PECO to maintain the $225 million interest, which, if not met, requires cash, which would otherwise be received by PECO under this program, to be held in escrow until the requirement is met. At June 30, 2002, PECO met this requirement.

12. RELATED-PARTY TRANSACTIONS (Exelon, ComEd, PECO and Generation)

Exelon and Generation

In February 2002, Generation entered into an agreement to loan AmerGen up to $75 million at an interest rate equal to the 1-month London Interbank Offering Rate plus 2.25%. As of June 30, 2002, $75 million had been loaned to AmerGen. In July 2002, the loan agreement and the loan were increased to $100 million and the maturity date was extended to July 1, 2003.

Generation has entered into PPAs dated December 18, 2001 and November 22, 1999 with AmerGen. Under the 2001 PPA, Generation has agreed to purchase from AmerGen all the energy from Unit No. 1 at Three Mile Island Nuclear Station from January 1, 2002 through December 31, 2014. Under the 1999 PPA, Generation has agreed to purchase from AmerGen all of the residual energy from Clinton Nuclear Power Station (Clinton), through December 31, 2002. Currently, the residual output approximates 25% of the total output of Clinton. For the three months ended June 30, 2002 and 2001, and for the six months ended June 30, 2002 and 2001, the amount of purchased power recorded in Purchased Power in Exelon's and Generation's Consolidated Statements of Income and Comprehensive Income is $60 million and $12 million and $116 million and $22 million, respectively. As of June 30, 2002 and December 31, 2001, Generation had a payable of $27 million and $3 million, respectively, resulting from these PPAs.

Under a service agreement dated March 1, 1999, Generation provides AmerGen with certain operation and support services to the nuclear facilities owned by AmerGen. This service agreement has an indefinite term and may be terminated by Generation or AmerGen on 90 days notice. Generation is compensated for these services in an amount agreed to in the work order, but not less than the higher of fully allocated costs for performing the services or the market price. For the three months ended June 30, 2002 and 2001, the amount charged to AmerGen for these services was $16 million. For the six months ended June 30, 2002 and 2001, the amount charged to AmerGen for these services was $30 million and $32 million, respectively. As of June 30, 2002 and December 31, 2001, Generation had a receivable of $61 million and $47 million, respectively, resulting from these services.

ComEd

ComEd had a note receivable from Unicom Investments Inc. of $1.3 billion at June 30, 2002 and December 31, 2001, relating to the December 1999 fossil plant sale, which is included in Deferred Debits and Other Assets in ComEd's Consolidated Balance Sheets. Interest income earned on this note receivable was $7 million and $14 million, respectively, for the three months ended June 30, 2002 and 2001 and was $15 million and $37 million, respectively, for the six months ended June 30, 2002 and 2001. Interest receivable due on this note was $15 million and $24 million at June 30, 2002 and December 31, 2001, respectively, and is included in Current Assets on ComEd's Consolidated Balance Sheets.

At December 31, 2000, ComEd had a $400 million receivable from PECO, which was repaid in the second quarter of 2001. Interest income earned on the receivable from PECO for the three months and six months ended June 30, 2001 was $2 million and $8 million, respectively.

At June 30, 2002 and December 31, 2001, ComEd had an $875 million and $937 million non-interest bearing receivable, respectively, from Exelon relating to the 2001 corporate restructuring. This receivable is reflected as a reduction of Shareholders' Equity in ComEd's Consolidated Balance Sheets and is expected to be settled over the years 2002 through 2008.

ComEd had a short-term payable of $59 million at June 30, 2002 and December 31, 2001, and a long-term payable of $260 million and $291 million at June 30, 2002 and December 31, 2001, respectively, to Generation primarily representing ComEd's legal requirements to remit collections of nuclear decommissioning costs from customers to Generation. These liabilities to Generation were included in Current Liabilities and Deferred Credits and Other Liabilities, respectively, on ComEd's Consolidated Balance Sheets.

ComEd paid common stock dividends to Exelon of $117 million and $85 million for the three months ended June 30, 2002 and 2001, respectively, and of $235 million and $148 million for the six months ended June 30, 2002 and 2001, respectively.

Effective January 1, 2001, ComEd entered into a PPA with Generation. Intercompany power purchases pursuant to the PPA for the three months ended June 30, 2002 and June 30, 2001 were $547 million and $585 million, respectively, and for the six months ended June 30, 2002 and 2001 were $1,079 million and $1,193 million, respectively. At June 30, 2002 and December 31, 2001, there was a $212 million and $183 million payable, respectively, to Generation for the PPA as well as other services provided which is included in Current Liabilities on ComEd's Consolidated Balance Sheets.

ComEd provides electric, transmission, and other ancillary services to Generation and Enterprises. These services were recorded in revenues and were $12 million and $13 million for the three months ended June 30, 2002 and 2001, respectively, and $23 million and $55 million for the six months ended June 30, 2002 and 2001, respectively. At June 30, 2002 and December 31, 2001, there was a $3 million and $26 million receivable, respectively, for services provided, which is included in Current Liabilities and Current Assets on ComEd's Consolidated Balance Sheets, respectively.

ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial and information technology services. Such services, provided at cost including applicable overhead, were $28 million and $33 million for the three months ended June 30, 2002 and 2001, respectively, of which $26 million and $30 million, respectively, was included in Operating and Maintenance from Affiliates on ComEd's Consolidated Statements of Income and Comprehensive Income and $2 million and $3 million, respectively, was capitalized. For the six months ended June 30, 2002 and 2001, charges for such services were $68 million and $63 million, of which $65 million and $58 million, respectively, was included in Operating and Maintenance from Affiliates on ComEd's Consolidated Statements of Income and Comprehensive Income and $3 million and $5 million, respectively, was capitalized. At June 30, 2002 and December 31, 2001, there was a $6 million and $14 million payable, respectively, to BSC for services provided which is included in Current Liabilities on ComEd's Consolidated Balance Sheets.

ComEd receives substation and transmission engineering and construction services under contracts with InfraSource. Such services totaling $6 million and $13 million for the three months ended June 30, 2002 and 2001, respectively, and totaling $13 million and $22 million for the six months ended June 30, 2002 and 2001, respectively, were capitalized.

ComEd has contracted with Exelon Services to provide energy conservation services to ComEd customers. The costs were $3 million and $8 million for the three months ended June 30, 2002 and 2001, respectively, and were $6 million and $12 million for the six months ended June 30, 2002 and 2001, respectively, and were included in Operating and Maintenance expense on ComEd's Consolidated Statements of Income and Comprehensive Income.

In order to benefit from economies of scale, ComEd processes certain invoice payments on behalf of Generation and BSC. Receivables at June 30, 2002 and December 31, 2001 from Generation for such service totaled $8 million and $21 million, respectively, and were included in Current Liabilities and Current Assets on ComEd's Consolidated Balance Sheets, respectively, and from BSC totaled $8 million and $19 million, respectively, and were included in Current Assets on ComEd's Consolidated Balance Sheets.

PECO

Effective January 1, 2001, Exelon contributed to PECO a $2.0 billion non-interest bearing receivable from Exelon related to the 2001 corporate restructuring. This receivable is reflected as a reduction of Shareholders' Equity in PECO's Consolidated Balance Sheets and is expected to be settled over the years 2002 through 2010. As of June 30, 2002 and December 31, 2001, the balance of this receivable from Exelon was $1.8 billion and $1.9 billion, respectively.

PECO paid common stock dividends to Exelon of $85 million and $56 million for the three months ended June 30, 2002 and 2001, respectively, and $170 million and $101 million for the six months ended June 30, 2002 and 2001, respectively.

Effective January 1, 2001, PECO entered into a PPA with Generation. Intercompany power purchases pursuant to the PPA were $346 million and $264 million for the three months ended June 30, 2002 and 2001, respectively, and $649 million and $508 million for the six months ended June 30, 2002 and 2001. As of June 30, 2002 and December 31, 2001, PECO's payable related to the PPA was $137 million and $90 million, respectively.

PECO receives a variety of corporate support services from BSC, including legal, human resources, financial and information technology services. Such services, provided at cost including applicable overhead, were $7 million and $15 million for the three months ended June 30, 2002 and 2001, respectively, and $13 million and $17 million for the six months ended June 30, 2002 and 2001, respectively. At June 30, 2002 and December 31, 2001, PECO had a $33 million and $41 million payable, respectively, to BSC.

PECO receives services from Enterprises for construction and the deployment of automated meter reading technology. Construction services totaling $10 million and $14 million were capitalized in the six months ended June 30, 2002 and 2001, respectively. Automated meter reading technology services totaling $8 million and $4 million for the three months ended June 30, 2002 and 2001, respectively, and totaling $16 million and $7 million for the six months ended June 30, 2002 and 2001, respectively, were included in Operating and Maintenance from Affiliates in the Consolidated Statements of Income and Comprehensive Income. At June 30, 2002 and December 31, 2001, PECO had $6 million and $8 million payable, respectively, to Enterprises.

At December 31, 2000, PECO had a $400 million payable to ComEd, which was repaid in the second quarter of 2001. The average annual interest rate on this payable for the period outstanding was 6.5%. Interest expense related to this payable for the three and six months ended June 30, 2001 was $2 million and $8 million, respectively.

PECO provides energy to Generation for Generation's own use. Intercompany sales for the three and six months ended June 30, 2002 and 2001 were $2 million and $3 million, respectively, in each period.

Generation

Generation had a short-term receivable of $59 million at June 30, 2002 and December 31, 2001, and a long-term receivable of $260 million and $291 million at June 30, 2002 and December 31, 2001, respectively, from ComEd primarily representing ComEd's legal requirements to remit collections of nuclear decommissioning costs from customers to Generation resulting from the restructuring. These receivables from ComEd were included in Current Assets and Deferred Debits and Other Assets, respectively, on Generation's Consolidated Balance Sheets.

Effective January 1, 2001, Generation entered into PPAs with ComEd and PECO. Intercompany power sales pursuant to the PPAs for the three months ended June 30, 2002 and 2001 were $893 million, including decommissioning revenue of $3 million, and $849 million, including decommissioning revenue of $3 million, respectively. For the six months ended June 30, 2002 and June 30, 2001 these intercompany power sales were $1,728 million, including decommissioning revenue of $6 million, and $1,701 million, including decommissioning revenue of $6 million, respectively. At June 30, 2002 and December 31, 2001, there was a $351 million and $273 million receivable, respectively, for the PPAs as well as other services provided which is included in Current Assets on Generation's Consolidated Balance Sheets.

Generation sells power to Exelon Energy. Power sales for the three months ended June 30, 2002 and 2001 were $60 million and $57 million, respectively, and for the six months ended June 30, 2002 and 2001 were $117 million and $118 million, respectively. At June 30, 2002 and December 31, 2001, there was a $21 million and $15 million receivable, respectively.

Generation purchases power from AmerGen under PPAs as discussed in the Exelon and Generation section of this note. Additionally, Generation purchases power from PECO for Generation's own use, buys back excess power from Exelon Energy and purchases transmission and ancillary services from ComEd. These purchases, including AmerGen, for the three months ended June 30, 2002 and 2001 were $75 million and $42 million, respectively, and for the six months ended June 30, 2002 and 2001 were $147 million and $60 million, respectively. At June 30, 2002 and December 31, 2001, there was a payable for these power purchases of $35 million and $26 million, respectively.

Generation receives a variety of corporate support services from BSC, including legal, human resources, financial and information technology services. Such services, provided at cost including applicable overhead, for the three months ended June 30, 2002 and June 30, 2001 were $16 million and $22 million, respectively, and $30 million and $35 million for the six months ended June 30, 2002 and June 30, 2001, respectively, and were included in Operating and Maintenance (O&M) expense on Generation's Consolidated Statements of Income and Comprehensive Income. At June 30, 2002 and December 31, 2001, there was an $8 million and an $18 million payable, respectively, to BSC for services provided which is included in Current Liabilities on Generation's Consolidated Balance Sheets.

In order to facilitate payment processing, ComEd processes certain invoice payments on behalf of Generation and BSC. Payables at June 30, 2002 and December 31, 2001 to ComEd for such services totaled $8 million and $21 million, respectively, and were included in Current Liabilities on Generation's Consolidated Balance Sheets.

In relation to the acquisition of two generating plants from TXU in April of 2002, Generation had a $331 million payable to Exelon at June 30, 2002. Interest expense related to this payable was $1 million for the three months and six months ended June 30, 2002.

In relation to the December 18, 2001 acquisition of 49.9% of Sithe common stock, Generation had a $700 million payable to Exelon, which was repaid in the second quarter of 2001. Interest expense related to this payable for the three and six months ended June 30, 2001 was $8 million and $23 million, respectively.

13. NEW ACCOUNTING PRONOUNCEMENTS (Exelon, ComEd, PECO and Generation)

In June 2001, the FASB issued SFAS No. 143, "Asset Retirement Obligations" (SFAS No. 143). In April 2002, the FASB issued SFAS No. 145, " Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS No. 145). In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS No. 146).

SFAS No. 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets. Exelon expects to adopt SFAS No. 143 on January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. Adoption of SFAS No. 143 will change the accounting for the decommissioning of Exelon's nuclear generating plants as well as certain other long-lived assets.

Currently, Generation records the obligation for decommissioning ratably over the lives of the plants. The January 1, 2003 adoption of SFAS No. 143 will require a cumulative effect adjustment effective the date of adoption to adjust plant assets and decommissioning liabilities to the values they would have been had this standard been employed from the in-service dates of the plants.

As it relates to nuclear decommissioning, the effect of this cumulative adjustment will be to change the decommissioning liability to reflect the fair value of the decommissioning obligation at the balance sheet date. Additionally, the standard will require the accrual of an asset related to the decommissioning obligation, which will be amortized over the remaining lives of the plants. The net difference between the asset recognized and the liability recorded upon adoption of SFAS No. 143 will be charged to earnings and recognized as a cumulative effect, net of expected regulatory recovery. The decommissioning liability to be recorded represents an obligation for the future decommissioning of the plants, and as a result accretion expense will be accrued on this liability until such time as the obligation is satisfied.

Exelon, ComEd, PECO and Generation are in the process of evaluating the impact of SFAS No. 143 on their financial statements, and cannot determine the ultimate impact of adoption at this time, however, the cumulative effect could be material to earnings. Additionally, although over the life of the plant the charges to earnings for the depreciation of the asset and the interest on the liability will be equal to the amounts currently recognized as decommissioning expense, the timing of those charges will change and in the near-term period subsequent to adoption, the depreciation of the asset and the interest on the liability could result in an increase in expense.

SFAS No. 145 eliminates SFAS No. 4 "Reporting Gains and Losses from Extinguishment of Debt" (SFAS No. 4) and thus allows for only those gains or losses on the extinguishment of debt that meet the criteria of extraordinary items to be treated as such in the financial statements. SFAS No. 145 also amends Statement of Financial Accounting Standards No. 13, "Accounting for Leases" (SFAS No. 13) to require sale-leaseback accounting for certain lease modifications that have economic effects that are similar to sale-leaseback transactions. The provisions of this statement relating to the rescission of SFAS No. 4 are effective for fiscal years beginning after May 15, 2002, the provisions of this statement relating to the amendment of SFAS No. 13 are effective for transactions occurring after May 15, 2002, and all other provisions of this Statement are effective for financial statements issued on or after May 15, 2002. Exelon, ComEd, PECO and Generation are in the process of evaluating the impact of SFAS No. 145 on their financial statements, and do not expect the impact to be material.

SFAS No. 146 requires that the liability for costs associated with exit or disposal activities be recognized when incurred, rather than at the date of a commitment to an exit or disposal plan. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002.

14. CHANGE IN ACCOUNTING ESTIMATE (Exelon, ComEd and Generation)

Effective April 1, 2001, Generation changed its accounting estimates related to the depreciation and decommissioning of certain generating stations. The estimated service lives were extended by 20 years for three nuclear stations, by periods of up to 20 years for certain fossil stations and by 50 years for a pumped storage station. Effective July 1, 2001, the estimated service lives were extended by 20 years for the remainder of Exelon's operating nuclear stations. These changes were based on engineering and economic feasibility studies performed by Generation considering, among other things, future capital and maintenance expenditures at these plants. As a result of the change, net income for the three months and six months ended June 30, 2002 increased $25 million ($16 million, net of income taxes) and $60 million ($36 million, net of income taxes), respectively.

Effective April 1, 2002, ComEd changed its accounting estimate related to the allowance for uncollectible accounts. This change was based on an independently prepared evaluation of the risk profile of ComEd's customer accounts receivable. As a result of the new evaluation, the allowance for uncollectible accounts reserve was reduced by $11 million in the second quarter of 2002.

15. SUBSEQUENT EVENTS

On July 1, 2002, Exelon Generation notified Midwest Generation of the exercise of its call options under the existing Coal Generation Purchase Power Agreement. Exelon Generation exercised options on 1,265 MWs of capacity and did not exercise options on 2,684 MWs of capacity. In 2003, Exelon Generation will take 1,696 MWs of non-option capacity and 1,265 MWs of option capacity under the existing contract.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Dollars in millions, unless otherwise noted)

EXELON CORPORATION

GENERAL

Exelon Corporation (Exelon), through its subsidiaries, operates in three business segments:

- Energy Delivery, consisting of the retail electricity distribution and transmission businesses of Commonwealth Edison Company (ComEd) in northern Illinois and PECO Energy Company (PECO) in southeastern Pennsylvania and the natural gas distribution business of PECO in the Pennsylvania counties surrounding the City of Philadelphia.
- Generation, consisting of Exelon Generation Company, LLC's (Generation) electric generating facilities, energy marketing operations and equity interests in Sithe Energies, Inc. (Sithe) and AmerGen Energy Company, LLC (AmerGen).
- Enterprises, consisting of Exelon Enterprises Company, LLC's (Enterprises) competitive retail energy sales, energy and infrastructure services, communications and other investments weighted towards the communications, energy services and retail services industries.

See Note 6 of the Combined Notes to Consolidated Financial Statements for further segment information.

Generation early adopted the provision of Emerging Issues Task Force (EITF) Issue 02-3 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3) issued by the Financial Accounting Standards Board (FASB) EITF in June 2002 that requires revenues and energy costs related to energy trading contracts to be presented on a net basis in the income statement. For comparative purposes, energy costs related to energy trading have been reclassified in prior periods to revenue to conform with the net basis of presentation required by EITF 02-3.

RESULTS OF OPERATIONS

Three Months Ended June 30, 2002 Compared To Three Months Ended June 30, 2001

Net Income and Earnings Per Share

Net income increased $170 million, or 54%, for the three months ended June 30, 2002. Diluted earnings per common share increased $0.53 per share, or 55%. The increase in net income reflects the gain on Enterprises' sale of its 49% interest in AT&T Wireless PCS of Philadelphia, LLC (AT&T Wireless), higher earnings in Energy Delivery, primarily related to an increase in retail sales due to warmer summer weather, the discontinuation of goodwill amortization at Energy Delivery and Enterprises required by the adoption of FASB Statement of Financial Accounting Standards (SFAS) No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142) and certain other factors affecting net income, which are discussed in the remainder of the results of operations section.

Exelon evaluates its performance on a business segments basis. The analysis below presents the operating results for each of its business segments for the three months ended June 30, 2002 compared to the three months ended June 30, 2001.

Corporate provides its business segments a variety of support services including legal, human resources, financial and information technology services. These costs are allocated to the business segments. Additionally, Corporate costs reflect costs for strategic long-term planning, certain governmental affairs, and interest costs and income from various investment and financing activities.

Net Income by Business Segment

	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Variance	% Change
Energy Delivery	$ 322	$ 264	$ 58	21.9%
Generation	84	71	13	18.3%
Enterprises	83	(5)	88	n.m.
Corporate	(4)	(15)	11	(73.3%)
Total	$ 485	$ 315	$ 170	53.9%

n.m. - not meaningful

Results of Operations - Energy Delivery Business Segment

	Three Months Ended June 30, 2002	Three Months Ended June 30, 2001	Variance	% Change
OPERATING REVENUES	$ 2,476	$ 2,436	$ 40	1.6%
OPERATING EXPENSES				
Purchased Power	958	901	57	6.3%
Fuel	53	79	(26)	(32.9%)
Operating and Maintenance	351	374	(23)	(6.1%)
Depreciation and Amortization	242	267	(25)	(9.4%)
Taxes Other Than Income	136	110	26	23.6%
Total Operating Expense	1,740	1,731	9	0.1%
OPERATING INCOME	736	705	31	4.4%
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(218)	(260)	42	(16.1%)
Distributions on Preferred Securities of Subsidiaries	(11)	(12)	1	(8.3%)
Other, net	15	24	(9)	(37.5%)
Total Other Income and Deductions	(214)	(248)	34	(13.7%)
INCOME BEFORE INCOME TAXES	522	457	65	14.2%
INCOME TAXES	200	193	7	3.6%
NET INCOME	$ 322	$ 264	$ 58	22.0%

Energy Delivery's gross margin (revenue net of purchased power and fuel) increased $9 million, $25 million of which was attributable to warmer summer weather in the second quarter of 2002 as compared to the second quarter of 2001 in the ComEd service territory, which increased retail electric volume. The retail increase was offset by lower wholesale sales volume.

Lower operating and maintenance expense reflects a reduction in bad debt expense due to a change in estimate and lower system repair and storm restoration costs, partially offset by costs associated with the deployment of automated meter reading technology and increased corporate allocations.

Energy Delivery's depreciation and amortization expense decreased by $25 million reflecting $33 million for the discontinuation of goodwill amortization due to the adoption of SFAS No. 142 as of January 1, 2002, partially offset by $9 million of higher regulatory asset amortization.

As required by the Illinois Restructuring Act, ComEd made a notification filing with the Illinois Commerce Commission (ICC) to reflect lower depreciation rates effective July 1, 2002. No ICC approval is required for the new rates to take effect. The anticipated annual reduction in depreciation expense is estimated to be approximately $100 million.

Lower interest expense reflects a reduction in debt outstanding and lower interest rates due to debt refinancing. The reduction in other, net, primarily reflects lower intercompany interest income reflecting lower interest rates.

Energy Delivery's effective income tax rate was 38.3% for the three months ended June 30, 2002, compared to 42.2% for the three months ended June 30, 2001. The decrease in the effective tax rate was primarily attributable to the discontinuation of goodwill amortization as of January 1, 2002, which was not deductible for income tax purposes, and a reduction in state income taxes.

Energy Delivery Operating Statistics and Revenue Detail

Energy Delivery's electric sales statistics and revenue detail are as follows:

Retail Deliveries - (in gigawatthours (GWh))	For the three months ended June 30, 2002	2001	% Change
Bundled Deliveries (1)			
Residential	7,977	6,905	15.5%
Small Commercial & Industrial	7,481	7,115	5.1%
Large Commercial & Industrial	6,049	5,920	2.2%
Public Authorities & Electric Railroads	1,885	2,072	(9.0%)
	23,392	22,012	6.3%
Unbundled Deliveries (2)			
Alternative Energy Suppliers			
Residential	557	848	(34.3%)
Small Commercial & Industrial	1,179	1,169	0.9%
Large Commercial & Industrial	1,635	1,983	(17.5%)
Public Authorities & Electric Railroads	181	95	90.5%
	3,552	4,095	(13.3%)
PPO (ComEd Only)			
Small Commercial & Industrial	839	798	5.1%
Large Commercial & Industrial	1,392	1,518	(8.3%)
Public Authorities & Electric Railroads	274	326	(16.0%)
	2,505	2,642	(5.2%)
Total Unbundled Deliveries	6,057	6,737	(10.1%)
Total Retail Deliveries	29,449	28,749	2.4%

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy. PECO's tariffed rates also include a Competitive Transition Charge (CTC).

(2) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier or ComEd's Power Purchase Option (PPO).

Electric Revenue	For the three months ended June 30, 2002	2001	Variance	% Change
Bundled Revenues (1)				
Residential	$ 801	$ 724	$ 77	10.6%
Small Commercial & Industrial	669	624	45	7.2%
Large Commercial & Industrial	404	367	37	10.1%
Public Authorities & Electric Railroads	121	126	(5)	(4.0%)
	1,995	1,841	154	8.4%
Unbundled Revenues (2)				
Alternative Energy Suppliers				
Residential	42	67	(25)	(37.3%)
Small Commercial & Industrial	30	41	(11)	(26.8%)
Large Commercial & Industrial	33	40	(7)	(17.5%)
Public Authorities & Electric Railroads	5	1	4	n.m.
	110	149	(39)	(26.2%)
PPO (ComEd Only)				
Small Commercial & Industrial	55	53	2	3.8%
Large Commercial & Industrial	76	86	(10)	(11.6%)
Public Authorities & Electric Railroads	17	19	(2)	(10.5%)
	148	158	(10)	(6.3%)
Total Unbundled Revenues	258	307	(49)	(16.0%)
Total Electric Retail Revenues	2,253	2,148	105	4.9%
Wholesale and Miscellaneous Revenue (3)	139	176	(37)	(21.0%)
Total Electric Revenue	$ 2,392	$ 2,324	$ 68	2.9%

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy. PECO's tariffed rates also include a CTC charge.
(2) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO. Revenue from customers choosing an alternative energy supplier includes a distribution charge and a CTC. Revenues from customers choosing ComEd's PPO includes an energy charge at market rates, transmission, and distribution charges and a CTC. Transmission charges received from alternative energy suppliers are included in wholesale and miscellaneous revenue.
(3) Wholesale and miscellaneous revenues include sales to alternative energy suppliers, transmission revenue, sales to municipalities and other wholesale energy sales.

The changes in electric retail revenues for the three months ended June 30, 2002, as compared to the same period in 2001 are attributable to the following:

	Variance
Rate Changes	$ (14)
Customer Choice	46
Weather	41
Other Effects	32
Electric Retail Revenue	$ 105

o Rate Changes. The decrease in revenues attributable to rate changes reflects the 5% ComEd residential rate reduction, effective October 1, 2001, required by the Illinois restructuring legislation partially offset by $13 million due to an increase in PECO's gross receipts tax rate. The increase in PECO's gross receipts tax rate will increase PECO's annual revenue and tax obligation by approximately $50 million in 2002.

- Customer Choice. All ComEd and PECO customers have the choice to purchase energy from other suppliers. This choice generally does not impact kWh deliveries, but affects revenue collected from customers related to energy supplied by Energy Delivery. On May 1, 2002, all ComEd residential customers were eligible to choose their supplier of electricity, however; as of June 30, 2002, no alternative electric supplier has sought approval from the ICC and no electric utilities have chosen to enter the ComEd residential market for the supply of electricity.

  The favorable customer choice effect is attributable to increased revenues of $85 million from customers in Pennsylvania selecting or returning to PECO as their electric generation supplier, partially offset by a decrease in revenues of $39 million from customers in Illinois electing to purchase energy from an Alternative Retail Electric Supplier (ARES) or the PPO, under which customers can purchase power from ComEd at a market-based rate. ComEd and PECO continue to collect delivery charges from these customers.
- Weather. The demand for electricity and gas services is impacted by weather conditions. Very warm weather in summer months and very cold weather in other months is referred to as "favorable weather conditions", because these weather conditions result in increased sales of electricity and gas. Conversely, mild weather reduces demand.

  The weather impact was favorable compared to the prior year as a result of warmer summer weather in the ComEd service territory during the second quarter of 2002 as compared to the same period in 2001.
- Other Effects. Other items increasing revenues were primarily related to a $39 million favorable volume variance other than weather, due to the impact of a strong housing construction market in Chicago partially offset by the impact of a slower economy on large commercial and industrial customers.

The reduction in wholesale revenue for the three months ended June 30, 2002 as compared to the three months ended June 30, 2001 reflects a $10 million decrease due to the expiration of wholesale contracts that were offered by ComEd from June 2000 to May 2001 to support the open access program in Illinois and a 2001 $15 million reversal of reserve for revenue refunds related to certain of ComEd's municipal customers as a result of a favorable FERC ruling.

On July 19, 2002, ComEd filed a request with the ICC to revise the Provider of Last Resort (POLR) obligation in Illinois. ComEd is seeking permission from the ICC to limit the availability by June 2006 of Rate 6L for 370 of ComEd's largest energy customers with demands of at least three MWs, totaling approximately 2,500 MWs. Rate 6L is a bundled fixed rate offered to large customers including heavy industrial plants, large office buildings, government facilities and a variety of other businesses. The ICC has 120 days to act on the filing or it will be deemed approved.

Energy Delivery's gas sales statistics and revenue detail are as follows:

	For the three months ended June 30, 2002	2001	Variance
Deliveries in million cubic feet (mmcf)	14,286	13,781	505
Revenue	$84	$ 112	$ (28)

The changes in gas revenue for the quarter ended June 30, 2002, as compared to the same 2001 period, are as follows:

(in millions)	Variance
Rate Changes	$ (28)
Weather	--
Volume	(1)
Other	1
Gas Revenue	$ (28)

- Rate Changes. The unfavorable variance in rates is attributable to an adjustment of the purchased gas cost recovery by the Pennsylvania Public Utilities Commission (PUC) effective in December 2001. The average rate per million cubic feet for all customers for the quarter ended June 30, 2002 was 28% lower than the same 2001 period. PECO's gas rates are subject to periodic adjustments by the PUC designed to recover or refund the difference between actual cost of purchased gas and the amount included in base rates and to recover or refund increases or decreases in certain state taxes not recovered in base rates.
- Weather. The weather impact was neutral during the quarter ended June 30, 2002 as compared to the same 2001 period. Heating degree-days were consistent in the quarter ended June 30, 2002 compared to the same 2001 period.
- Volume. Exclusive of weather impacts, delivery volume was consistent for the quarter ended June 30, 2002 compared to the same 2001 period.

Results of Operations - Generation Business Segment

	Three Months Ended June 30, 2002	2001	Variance	% Change
OPERATING REVENUES	$ 1,559	$1,583	$ (24)	(1.5%)
OPERATING EXPENSES				
Purchased Power	705	721	(16)	(2.2%)
Fuel	224	230	(6)	(2.6%)
Operating and Maintenance	411	405	6	1.5%
Depreciation and Amortization	65	75	(10)	(13.3%)
Taxes Other Than Income	41	39	2	5.1%
Total Operating Expense	1,446	1,470	(24)	(1.6%)
OPERATING INCOME	113	113	--	--
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(11)	(26)	15	(57.6%)
Equity in Earnings (Losses) of Unconsolidated Affiliates, net	9	13	(4)	(30.8%)
Other, net	24	14	10	71.4%
Total Other Income and Deductions	22	1	21	n.m.
INCOME BEFORE INCOME TAXES	135	114	21	18.4%
INCOME TAXES	51	43	8	18.6%
NET INCOME	$ 84	$ 71	13	18.3%

Net income for the three months ended June 30, 2002 was positively impacted by increased revenue from retail affiliates, increased revenue from the acquisition of two generating plants in April 2002 and reduced depreciation and interest expense, partially offset by depressed wholesale market prices for energy. Operating revenues, net of fuel and purchased power, decreased by $2 million. Lower wholesale market prices for energy reduced margins by $46 million, which were partially offset by increased revenue from affiliates of $43 million, revenue from the two generating plants acquired in April 2002, and lower fuel costs. Operating and maintenance expense increased by $6 million due to additional employee benefit costs of $9 million and operating costs for two generating plants acquired in April 2002 of $3 million. These additional expenses were partially offset by $7 million less in nuclear outage costs and other operating cost reductions including savings from Exelon's Cost Management Initiative. The decline in depreciation expense reflects extension of the estimated service lives of certain generating stations in the third quarter of 2001, partially offset by additional depreciation expense on plant placed in service after June 30, 2001, including the acquisition of two generating plants in April 2002. Lower interest expense is due to capitalized interest and a lower interest rate on the spent nuclear fuel obligation. Additionally, revenue for the three months ended June 30, 2002 includes a net trading portfolio loss of $16 million compared to a net $6 million loss for the three months ended June 30, 2001.

Generation Operating Statistics:

For the three months ended June 30, 2002 and 2001, Generation's sales and the supply of these sales exclusive of the trading portfolio were as follows:

	Three Months Ended June 30,	
Sales (in GWhs)	2002	2001
Energy Delivery	28,294	28,105
Exelon Energy	1,355	1,415
Market Sales	20,589	18,548
Total Sales	50,238	48,068

	Three Months Ended June 30,	
Supply of Sales (in GWhs)	2002	2001
Nuclear Generation	28,353	28,443
Purchases - non-trading portfolio	18,220	16,392
Fossil and Hydro Generation	3,665	3,233
Total Supply	50,238	48,068

Trading volume was 8,566 GWhs and 454 GWhs for the three months ended June 30, 2002 and 2001, respectively.

Generation's average margin data for the three months ended June 30, 2002 and 2001 were as follows:

	Three Months Ended June 30,	
($/MWh)	2002	2001
Average Realized Revenue		
Energy Delivery	$ 31.45	$ 30.09
Exelon Energy	44.73	40.11
Market Sales	30.69	37.69
Total Sales - excluding the trading portfolio	31.50	33.32
Average Supply Cost - excluding the trading portfolio	$ 18.79	$ 20.05
Average Margin - excluding the trading portfolio	$ 12.71	$ 13.27

Generation's nuclear fleet, including AmerGen, performed at a capacity factor of 92.1% for the three months ended June 30, 2002 compared to 93.6% the same period in 2001. The lower capacity factor is primarily due to 72 planned outage days in the three months ended June 30, 2002 versus 31 days in the same period in 2001, including AmerGen. Generation's nuclear units' production costs including AmerGen for the three months ended June 30, 2002 were $12.54 per MWh compared to $13.02 per MWh for the same period in 2001. The reduced unit production costs reflect additional generation due to power uprates, which more than offset the lower capacity factor, and lower production costs due to headcount reductions and Exelon's Cost Management Initiative in the three months ended June 30, 2002 as compared to the same period in 2001. Generation's average purchased power costs for wholesale operations were $39.96 per MWh for the three months ended June 30, 2002, compared to $45.27 per MWh for the same period in 2001. The decrease in purchased power costs was primarily due to depressed wholesale power market prices.

Results of Operations - Enterprises Business Segment

	Three Months Ended June 30, 2002	2001	Variance	% Change
OPERATING REVENUES	$ 476	$ 546	$ (70)	(12.8%)
OPERATING EXPENSES				
Purchased Power	56	61	(5)	(8.2%)
Fuel	82	100	(18)	(18.0%)
Operating and Maintenance	334	382	(48)	(12.5%)
Depreciation and Amortization	17	16	1	6.2%
Taxes Other Than Income	2	3	(1)	(33.3%)
Total Operating Expense	491	562	(71)	(12.6%)
OPERATING INCOME	(15)	(16)	1	(6.2%)
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(3)	(9)	6	(66.6%)
Equity in Earnings (Losses) of Unconsolidated Affiliates, net	2	(6)	8	(133.3%)
Other, net	158	21	137	n.m.
Total Other Income and Deductions	157	6	151	n.m.
INCOME BEFORE INCOME TAXES	142	(10)	152	n.m.
INCOME TAXES	59	(5)	64	n.m.
NET INCOME	$ 83	$ (5)	$ 88	n.m.

Enterprises' net income increased $88 million for the three months ended June 30, 2002 compared to the same period in 2001. The increase in net income is primarily attributable to the sale of Enterprises' 49% interest in AT&T Wireless PCS of Philadelphia, LLC (AT&T Wireless) to a subsidiary of AT&T Wireless Services for $285 million in cash that resulted in an after-tax gain of $116 million and higher equity in earnings of unconsolidated affiliates of $8 million primarily as a result of the discontinuance of losses on AT&T Wireless. These increases were partially offset by $36 million of investment write-downs and $4 million of net asset write-downs.

Operating revenues decreased $70 million, or 13%, for the three months ended June 30, 2002, compared to the same period in 2001. The decrease in operating revenues was attributable to lower gas sales of $12 million primarily resulting from lower gas prices, reduced retail energy sales of $20 million from Exelon Energy, Inc. (Exelon Energy) due to exiting the retail energy business in the Pennsylvania, New Jersey and Maryland area (PJM market), lower revenues of $43 million from Exelon Services, Inc. (Exelon Services) from reduced volume of construction project revenues and lower revenues of $19 million from InfraSource, Inc. (InfraSource) from the continued decline in the telecommunications industry and reduced volume of construction services in that industry. These decreases were partially offset by higher electric revenues of $22 million primarily resulting from higher electric prices in Illinois for Exelon Energy.

Enterprises' operating and other expenses, net decreased $222 million for the three months ended June 30, 2002 compared to the same period in 2001. The decrease is primarily attributable to a pre-tax gain of $198 million recorded on the AT&T Wireless sale, lower gas costs of $18 million primarily resulting from lower gas prices, lower power costs of $20 million resulting from reduced operations of retail energy sales from Exelon Energy exiting the PJM market, reduced costs relating to lower construction project volume at Exelon Services of $33 million, reduced costs relating to lower volume of construction services in the telecommunications industry at InfraSource of $18 million, higher equity in earnings of unconsolidated affiliates of $8 million primarily as a result of the discontinuance of losses on AT&T Wireless as a result of the AT&T Wireless sale and lower interest expense of $6 million. These decreases were partially offset by higher electric purchased power costs in Illinois of $21 million for Exelon Energy, write-downs of communications investments of $27 million, write-downs of energy related investments of $9 million, a net write-down of other assets of $4 million in 2002 and an $18 million gain in 2001 from the sale of a communications investment.

The effective income tax rate was 41.5% for the three months ended June 30, 2002, compared to 50.0% for the three months ended June 30, 2001. The decrease in the effective tax rate was primarily attributable to the discontinuation of goodwill amortization as of January 1, 2002, that was not deductible for income tax purposes and a true-up of income taxes relating to a merger between two Enterprises businesses in April 2001, partially offset by the effect of the AT&T Wireless sale.

Six Months Ended June 30, 2002 Compared To Six Months Ended June 30, 2001

Net Income and Earnings Per Share

Exelon's income before the cumulative effect of changes in accounting principles increased $20 million, or 3%, for the six months ended June 30, 2002. Diluted earnings per common share on the same basis increased $0.06 per share, or 3%. The increase in income before the cumulative effect of changes in accounting principles reflects higher earnings due to the sale of AT&T Wireless, warmer summer weather, and the discontinuation of goodwill amortization required by the adoption of SFAS No. 142, partially offset by a decrease in retail sales due to mild winter weather, lower wholesale energy prices, increased nuclear refueling outage costs, employee severance costs and certain other factors affecting net income, which are discussed in the remainder of the results of operations section. Net income included net pretax charges of $10 million for severance costs, primarily related to executive severance.

Net income decreased $222 million, or 31%, for the six months ended June 30, 2002. Diluted earnings per common share decreased $0.69 per share, or 31%. Net income for the six months ended June 30, 2002 includes a $230 million charge for the cumulative effect of changes in accounting principles, reflecting goodwill impairment upon the adoption of SFAS No. 142. Net income for the six months ended June 30, 2001 includes $12 million of income for the cumulative effect of adopting SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133). See Note 2 of the Combined Notes to Consolidated Financial Statements for further information regarding the adoption of SFAS No. 133.

The analysis below presents the operating results for each of Exelon's business segments for the six months ended June 30, 2002 compared to the six months ended June 30, 2001.

Income Before Cumulative Effect of Changes in Accounting Principles by Business Segment

	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001	Variance	% Change
Energy Delivery	$ 538	$ 530	$ 8	1.5%
Generation	150	229	(79)	(34.4%)
Enterprises	55	(30)	85	n.m.
Corporate	(21)	(27)	6	(22.2%)
Total	$ 722	$ 702	$ 20	2.8%

Results of Operations - Energy Delivery Business Segment

	Six Months Ended June 30, 2002	Six Months Ended June 30, 2001	Variance	% Change
OPERATING REVENUES	$ 4,811	$4,933	$ (122)	(2.4%)
OPERATING EXPENSES				
Purchased Power	1,846	1,793	53	2.9%
Fuel	188	284	(96)	(33.8%)
Operating and Maintenance	724	724	--	--
Depreciation and Amortization	489	535	(46)	(8.5%)
Taxes Other Than Income	268	225	43	19.1%
Total Operating Expense	3,515	3,561	(46)	(1.2%)
OPERATING INCOME	1,296	1,372	(76)	(5.5%)
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(439)	(506)	67	(13.2%)
Distributions on Preferred Securities of Subsidiaries	(23)	(23)	--	--
Other, net	30	71	(41)	(57.7%)
Total Other Income and Deductions	(432)	(458)	26	(5.6%)
INCOME BEFORE INCOME TAXES	864	914	(50)	(5.5%)
INCOME TAXES	326	384	(58)	(15.1%)
NET INCOME	$ 538	$ 530	$ 8	1.5%

Energy Delivery's gross margin (revenue net of purchased power and fuel) declined $79 million, $26 million of which was attributable primarily to warmer winter weather, partially offset by warmer summer weather in the ComEd service territory during the second quarter of 2002, which reduced retail electric and gas volumes, and a reduction in wholesale sales volumes.

Flat operating and maintenance expense reflects increased pension and postretirement benefit costs and increased corporate allocations, including a portion of executive severance charges, and an increase in the provision for injuries and damages offset by decreased system repair and storm damage costs, a decrease in the provision for bad debt expense, and a decrease in the provision for obsolete inventory.

Energy Delivery's depreciation and amortization expense decreased by $46 million reflecting $64 million for the discontinuation of goodwill amortization due to the adoption of SFAS No. 142 as of January 1, 2002, partially offset by $17 million of higher regulatory asset amortization.

Lower interest expense reflects reductions in debt outstanding and lower interest rates due to debt refinancing. The reduction in other - net, primarily reflects lower intercompany interest income reflecting lower interest rates.

Energy Delivery's effective income tax rate was 37.7% for the six months ended June 30, 2002, compared to 42.0% for the six months ended June 30, 2001. The decrease in the effective tax rate was primarily attributable to the discontinuation of goodwill amortization as of January 1, 2002, which was not deductible for income tax purposes, and a reduction in state income taxes.

Energy Delivery Operating Statistics and Revenue Detail

Energy Delivery's electric sales statistics and revenue detail are as follows:

	For the six months ended June 30,		
Retail Deliveries - (in GWhs)	2002	2001	% Change
Bundled Deliveries (1)			
Residential	16,441	15,670	4.9%
Small Commercial & Industrial	14,687	13,991	5.0%
Large Commercial & Industrial	11,357	11,341	0.1%
Public Authorities & Electric Railroads	3,879	4,275	(9.3%)
	46,364	45,277	2.4%
Unbundled Deliveries (2)			
Alternative Energy Suppliers			
Residential	1,348	1,375	(2.0%)
Small Commercial & Industrial	2,280	2,523	(9.6%)
Large Commercial & Industrial	3,124	4,335	(27.9%)
Public Authorities & Electric Railroads	320	143	123.8%
	7,072	8,376	(15.6%)
PPO (ComEd Only)			
Small Commercial & Industrial	1,602	1,622	(1.2%)
Large Commercial & Industrial	2,703	2,876	(6.0%)
Public Authorities & Electric Railroads	516	584	(11.6%)
	4,821	5,082	(5.1%)
Total Unbundled Deliveries	11,893	13,458	(11.6%)
Total Retail Deliveries	58,257	58,735	(0.8%)

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy. PECO's tariffed rates also include a CTC charge.
(2) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO.

Electric Revenue	For the six months ended June 30, 2002	2001	Variance	% Change
Bundled Revenues (1)				
Residential	$ 1,563	$ 1,538	$ 25	1.6%
Small Commercial & Industrial	1,249	1,144	105	9.2%
Large Commercial & Industrial	750	687	63	9.2%
Public Authorities & Electric Railroads	230	250	(20)	(8.0%)
	3,792	3,619	173	4.8%
Unbundled Revenues (2)				
Alternative Energy Suppliers				
Residential	96	103	(7)	(6.8%)
Small Commercial & Industrial	48	94	(46)	(48.9%)
Large Commercial & Industrial	45	102	(57)	(55.9%)
Public Authorities & Electric Railroads	7	3	4	133.3%
	196	302	(106)	(35.1%)
PPO (ComEd Only)				
Small Commercial & Industrial	98	90	8	8.9%
Large Commercial & Industrial	140	146	(6)	(4.1%)
Public Authorities & Electric Railroads	29	31	(2)	(6.5%)
	267	267	--	--
Total Unbundled Revenues	463	569	(106)	(18.6%)
Total Electric Retail Revenues	4,255	4,188	67	1.6%
Wholesale and Miscellaneous Revenue (3)	263	338	(75)	(22.2%)
Total Electric Revenue	$ 4,518	$ 4,526	$ (8)	(0.2%)

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy. PECO's tariffed rates also include a CTC charge.
(2) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier or ComEd's PPO. Revenue from customers choosing an alternative energy supplier includes a distribution charge and a CTC. Revenues from customers choosing ComEd's PPO includes an energy charge at market rates, transmission, and distribution charges and a CTC. Transmission charges received from alternative energy suppliers are included in wholesale and miscellaneous revenue.
(3) Wholesale and miscellaneous revenues include sales to alternative energy suppliers, transmission revenue, sales to municipalities and other wholesale energy sales.

The changes in electric retail revenues for the six months ended June 30, 2002, as compared to the same period in 2001 are attributable to the following:

	Variance
Rate Changes	$ (15)
Customer Choice	87
Weather	(31)
Other Effects	26
Electric Retail Revenue	$ 67

o Rate Changes. The decrease in revenues attributable to rate changes reflects the 5% ComEd residential rate reduction, effective October 1, 2001, required by the Illinois restructuring legislation and the timing of a $60 million PECO rate reduction effective January 1, 2001 offset by $26 million due to an increase in PECO's gross receipts tax rate and the expiration of a 6% reduction in PECO's rates during the first quarter of 2001.

- Customer Choice. The favorable customer choice effect is attributable to increased revenues of $165 million from customers in Pennsylvania selecting or returning to PECO as their electric generation supplier, partially offset by a decrease in revenues of $78 million from customers in Illinois electing to purchase energy from an ARES or the PPO, under which customers can purchase power from ComEd at a market-based rate. ComEd and PECO continue to collect delivery charges from these customers.
- Weather. The weather impact was unfavorable compared to the prior year as a result of warmer winter weather in ComEd and PECO service territories partially offset by warmer summer weather in the ComEd service territory during the second quarter of 2002 as compared to the same period in 2001.
- Other Effects. Other items decreasing revenues were primarily related to a net $58 million favorable volume variance other than weather, primarily due to the impact of a strong housing construction market in Chicago, partially offset by the payment of $14 million to Generation related to nuclear decommissioning cost recovery under an agreement effective September 2001 which reduced PECO's revenue compared to the prior year, an $11 million settlement of CTCs by a large PECO customer in 2001 and the impact of a slower economy on large commercial and industrial customers.

The reduction in wholesale revenue for the six months ended June 30, 2002 as compared to the six months ended June 30, 2001 was due primarily to a decrease in off-system sales due to the expiration of wholesale contracts that were offered by ComEd from June 2000 to May 2001 to support the open access program in Illinois, and a 2001 reversal of reserve for revenue refunds related to certain of ComEd's municipal customers as a result of a favorable FERC ruling.

Energy Delivery's gas sales statistics and revenue detail are as follows:

	For the six months ended June 30,		
	2002	2001	Variance
Deliveries in mmcf	45,643	48,011	(2,368)
Revenue	$ 293	$ 407	$(114)

The changes in gas revenue for the six months ended June 30, 2002, as compared to the same 2001 period, are as follows:

	Variance
Rate Changes	$ (63)
Weather	(30)
Volume	(22)
Other	1
Gas Revenue	$ (114)

- Rate Changes. The unfavorable variance in rates is attributable to an adjustment of the purchased gas cost recovery by the PUC effective in December 2001. The average rate per million cubic feet for all customers for the quarter ended June 30, 2002 was 24% lower than the same 2001 period.
- Weather. The unfavorable weather impact is attributable to warmer winter weather during the six months ended June 30, 2002 as compared to the same 2001 period. Heating degree-days decreased 15% in the six months ended June 30, 2002 compared to the same 2001 period.
- Volume. Exclusive of weather impacts, lower delivery volume affected revenue by $22 million in the six months ended June 30, 2002 compared to the same 2001 period. Total deliveries to retail customers decreased 5% in the six months ended June 30, 2002 compared to the same 2001 period, primarily as a result of slower economic conditions in 2002 offset by increased customer growth.

Results of Operations - Generation Business Segment

	Six Months Ended June 30,			
	2002	2001	Variance	% Change
OPERATING REVENUES	$ 3,020	$3,211	$ (191)	(5.9%)
OPERATING EXPENSES				
Purchased Power	1,323	1,320	3	--
Fuel	433	449	(16)	(3.5%)
Operating and Maintenance	844	809	35	4.3%
Depreciation and Amortization	128	167	(39)	(23.3%)
Taxes Other Than Income	90	85	5	5.8%
Total Operating Expense	2,818	2,830	(12)	--
OPERATING INCOME	202	381	(179)	(46.9%)
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(28)	(59)	31	(52.5%)
Equity in Earnings of Unconsolidated Affiliates, net	32	39	(7)	(17.9%)
Other, net	40	18	22	122.2%
Total Other Income and Deductions	44	(2)	46	n.m.
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	246	379	(133)	(35.0%)
INCOME TAXES	96	150	(54)	(36.0%)
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	150	229	(79)	(34.4%)
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	13	12	1	8.3%
NET INCOME	$ 163	$ 241	(78)	(32.3%)

Net income for the six months ended June 30, 2002 was adversely impacted by a lower margin on wholesale energy sales due to depressed market prices for energy, a reduced supply of low-cost nuclear generation, and increased operating and maintenance expense partially offset by an increase in revenue from affiliates and lower depreciation and interest expense. Operating revenues, net of fuel and purchased power, decreased by $178 million. Lower wholesale market prices for energy reduced margins by $184 million, which was partially offset by increased revenues from affiliates of $26 million and lower fuel costs. The amount of low-cost nuclear generation available for sale was reduced due to an increased number of nuclear generating station refueling outages in the six months ended June 30, 2002, as compared to the same period in 2001. Operating and maintenance expense increased by $35 million, primarily due to $55 million of costs incurred for the additional refueling outages and the acquisition of two generating plants in April 2002. These additional expenses were partially offset by other operating cost reductions, including $10 million related to headcount reductions, a $10 million reduction in Generation's severance accrual and $4 million in savings related to Exelon's Cost Management Initiative. The decline in depreciation expense reflects extension of the estimated service lives of generating stations in the third quarter of 2001, partially offset by additional depreciation expense on plant placed in service after June 30, 2001, including the acquisition of two generating plants in April 2002. Lower interest expense is due to capitalized interest and a lower interest rate on the spent nuclear fuel obligation. Additionally, trading activities were initiated in April 2001. Revenue for the six months ended June 30, 2002 includes a net trading portfolio loss of $16 million compared to a net $6 million loss in the six months ended June 30, 2001.

Generation Operating Statistics:

For the six months ended June 30, 2002 and 2001, Generation's sales and the supply of these sales, excluding the trading portfolio, were as follows:

	Six Months Ended June 30,	
Sales (in GWhs)	2002	2001
Energy Delivery	56,044	57,309
Exelon Energy	2,605	3,006
Market Sales (1)	39,913	36,007
Total Sales	98,562	96,322

Supply of Sales (in GWhs)	Six Months Ended June 30, 2002	2001
Nuclear Generation	55,886	58,410
Purchases - non-trading portfolio	36,314	31,954
Fossil and Hydro Generation	6,362	5,958
Total Supply	98,562	96,322

Trading volume was 22,805 GWhs and 454 GWhs for the six months ended June 30, 2002 and 2001, respectively.

Generation's average margin data for the six months ended June 30, 2002 and 2001 were as follows:

($/MWh)	Six Months Ended June 30, 2002	2001
Average Realized Revenue		
Energy Delivery	$ 30.73	$ 29.58
Exelon Energy	45.08	39.30
Market Sales	29.44	38.66
Total Sales - excluding the trading portfolio	30.58	33.27
Average Supply Cost - excluding the trading portfolio	$ 17.78	$ 18.75
Average Margin - excluding the trading portfolio	$ 12.80	$ 14.52

Generation's nuclear fleet, including AmerGen, performed at a capacity factor of 91.2% for the six months ended June 30, 2002 compared to 96.2% the same period in 2001. Generation's nuclear units' production costs, including AmerGen, for the six months ended June 30, 2002 were $13.38 per MWh compared to $12.34 per MWh for the same period in 2001. The lower capacity factor and increased unit production costs are primarily due to 153 days of planned outage time in the six months ended June 30, 2002 versus 31 days in the same period in 2001. Generation's average purchased power costs for wholesale operations were $36.76 per MWh for the six months ended June 30, 2002, compared to $41.81 per MWh for the same period in 2001. The decrease in purchased power costs was primarily due to depressed wholesale power market prices.

Results of Operations - Enterprises Business Segment

	Six Months Ended June 30, 2002	2001	Variance	% Change
OPERATING REVENUES	$ 966	$1,213	$ (247)	(20.4%)
OPERATING EXPENSES				
Purchased Power	108	157	(49)	(31.2%)
Fuel	234	365	(131)	(35.9%)
Operating and Maintenance	634	705	(71)	(10.1%)
Depreciation and Amortization	35	31	4	12.9%
Taxes Other Than Income	5	7	(2)	(28.6%)
Total Operating Expense	1,016	1,265	(249)	(19.7%)
OPERATING INCOME	(50)	(52)	2	(3.9%)
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(8)	(22)	14	(63.6%)
Equity in Earnings (Losses) of Unconsolidated Affiliates, net	(5)	(14)	9	(64.3%)
Other, net	158	38	120	n.m.
Total Other Income and Deductions	145	2	143	n.m.
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	95	(50)	145	n.m
INCOME TAXES	40	(20)	60	n.m
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	55	(30)	85	n.m
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	(243)	--	(243)	n.m.
NET INCOME	$ (188)	$ (30)	$ (158)	n.m.

Enterprises' net income increased $85 million for the six months ended June 30, 2002 compared to the same period in 2001, excluding the cumulative effect of a change in accounting principle. The increase in net income is primarily attributable to the AT&T Wireless sale that resulted in an after-tax gain of $116 million and higher equity in earnings of unconsolidated affiliates of $9 million primarily as a result of the discontinuation of losses on AT&T Wireless as a result of the AT&T Wireless sale. These increases were partially offset by $40 million of investment write-downs and $4 million of net asset write-downs. Enterprises' net loss increased $158 million after reflecting the cumulative effect of a change in accounting principle resulting from the adoption of SFAS No. 142, which no longer allows amortization of goodwill but requires testing goodwill for impairment on an annual basis. The impairment booked during the first quarter, as a result of transitional impairment testing, was $243 million net of income taxes and minority interest.

Operating revenues decreased $247 million for the six months ended June 30, 2002, compared to the same period in 2001. The decrease in operating revenues is attributable to lower gas sales of $116 million primarily resulting from lower gas prices, reduced retail energy sales of

$91 million from Exelon Energy exiting the PJM market, lower revenues of $56 million from Exelon Services from reduced volume of construction projects and lower revenues of $29 million from InfraSource from the continued decline in the telecommunications industry and reduced volume of construction services in that industry. These decreases were partially offset by higher electric revenues of $45 million primarily resulting from higher electric prices in Illinois for Exelon Energy.

Enterprises' operating and other expenses, net decreased $392 million for the six months ended June 30, 2002 compared to the same period in 2001. The decrease is primarily attributable to a pre-tax gain of $198 million recorded on the AT&T Wireless sale, lower gas costs of $107 million primarily resulting from lower gas prices, lower purchased power costs of $114 million resulting from reduced operations of retail energy sales from Exelon Energy exiting the PJM market, reduced costs relating to lower construction project volume at Exelon Services of $45 million, reduced costs relating to lower volume of construction services in the telecommunications industry at InfraSource of $23 million, lower interest expense of $14 million, and higher equity in earnings of unconsolidated affiliates of $9 million primarily as a result of the discontinuance of losses on AT&T Wireless as a result of the AT&T Wireless sale. These decreases were partially offset by higher electric purchased power costs in Illinois of $42 million for Exelon Energy, write-downs of communications investments of $29 million, write-downs of energy related investments of $11 million, a net write-down of other assets of $4 million in 2002 and a $28 million gain in 2001 from the sales of communications investments.

The effective income tax rate was 42.1% for the six months ended June 30, 2002, compared to 40.0% for the six months ended June 30, 2001. The increase in the effective tax rate was primarily attributable to the AT&T Wireless sale offset by the discontinuation of goodwill amortization as of January 1, 2002, that was not deductible for income tax purposes.

LIQUIDITY AND CAPITAL RESOURCES

Exelon's businesses are capital intensive and require considerable capital resources. Exelon's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financings including the issuance of commercial paper. Exelon's access to external financing at reasonable terms is dependent on the credit ratings of Exelon and its subsidiaries and the general business condition of Exelon and the utility industry. Capital resources are used primarily to fund Exelon's capital requirements, including construction, investments in new and existing ventures, repayments of maturing debt and preferred securities of subsidiaries and payment of common stock dividends. Any potential future acquisitions could require external financing, including the issuance by Exelon of common stock.

Cash Flows from Operating Activities

Cash flows provided by operations for the six months ended June 30, 2002 were $1.6 billion compared to $2.0 billion in the six months ended June 30, 2001. Approximately 70% of 2002 cash flows provided by operations for the six months ended June 30, 2002 were provided by Energy Delivery and approximately 30% was provided by Generation. Enterprises' cash flows from operations were immaterial to Exelon for the six months ended June 30, 2002. Energy Delivery's cash flows from operating activities primarily result from sales of electricity and gas to a stable and diverse base of retail customers at fixed prices and are weighted toward the third quarter. Energy Delivery's future cash flows will depend upon the ability to achieve cost savings in operations, and the impact of the economy, weather and customer choice on its revenues. Generation's cash flows from operating activities primarily result from the sale of electric energy to wholesale customers, including Energy Delivery and Enterprises. Generation's future cash flow from operating activities will depend upon future demand and market prices for energy and the ability to continue to produce and supply power at competitive costs. Although the amounts may vary from period to period as a result of the uncertainties inherent in business, Exelon expects that Energy Delivery and Generation will continue to provide a reliable and steady source of internal cash flow from operations for the foreseeable future.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2002 were $1.3 billion, compared to $998 million for the six months ended June 30, 2001. The increase was primarily attributable to the $443 million acquisition of two generating plants from TXU Corp. (TXU) and increased capital expenditures partially offset by $285 million of proceeds from the AT&T Wireless sale. Capital expenditures other than the TXU acquisition, by business segment for the six months ended June 30, 2002 and 2001 are as follows:

	Six Months Ended June 30,	
	2002	2001
Energy Delivery	$ 495	$ 581
Generation	475	301
Enterprises	28	37
Corporate and Other	30	18
Total Capital Expenditures	$ 1,028	$ 937

Energy Delivery's capital expenditures for 2002 reflect the continuation of efforts to further improve the reliability of its distribution system in the Chicago region. Energy Delivery's investing activities were funded primarily through operating activities.

Generation's capital expenditures for 2002 are for additions to and upgrades of existing facilities (including nuclear refueling outages), nuclear fuel, and increases in capacity at existing plants. Generation's investing activities were funded from operating activities, borrowings from Exelon and the use of available cash.

Generation closed the purchase of the two natural-gas and oil-fired generating plants from TXU on April 25, 2002. The $443 million purchase was funded with available cash and Exelon commercial paper. Exelon expects to repay the commercial paper utilizing Generation's internal cash flows.

Capital expenditures have increased for the six months ended June 30, 2002 as compared to 2001 due to higher nuclear fuel expenditures, growth and an increase in the number of planned refueling outages, during which significant work is performed for additions to or upgrades of existing facilities.

In February 2002, Generation entered into an agreement to loan AmerGen up to $75 million at an interest rate of one-month LIBOR plus 2.25%. As of June 30, 2002, AmerGen had borrowed $75 million under this agreement. In July 2002, the loan agreement and the loan were increased to $100 million and the maturity date was extended to July 1, 2003.

Enterprises' capital expenditures for 2002 are primarily for additions to or upgrades of existing facilities. On April 1, 2002, Exelon Enterprises closed on the sale of its 49% interest in AT&T Wireless for $285 million in cash. Proceeds from the transaction will be used for Exelon's general corporate purposes.

Cash Flows from Financing Activities

Cash flows used in financing activities were $142 million in the second quarter 2002, primarily attributable to debt service and payments of dividends on common stock of $280 million. Debt financing activities during the six months ended June 30, 2002 were as follows:

- ComEd issued $600 million in First Mortgage Bonds, issued $100 million of Illinois Development Finance Authority floating-rate Pollution Control Revenue Refunding Bonds, redeemed $100 million of 7.25% Illinois Development Finance Authority Pollution Control Revenue Refunding Bonds, redeemed $200 million in First Mortgage Bonds with available cash and retired $170 million of transitional trust notes,
- PECO borrowed an additional $74 million of commercial paper and made principal payments of $207 million on long-term debt with available cash.

Credit Issues

Exelon meets its short-term liquidity requirements primarily through the issuance of commercial paper by Exelon, ComEd and PECO. Exelon, along with ComEd, PECO and Generation, entered into a $1.5 billion unsecured revolving credit facility with a group of banks. This credit facility is used principally to support the commercial paper programs of Exelon, ComEd and PECO.

At June 30, 2002, Exelon's capital structure consisted of 60% of long-term debt, 35% common stock, 2% notes payable and 3% preferred securities of subsidiaries. Total debt included $6.6 billion of securitization debt constituting obligations of certain consolidated special purpose entities, representing 28% of capitalization.

At June 30, 2002, Exelon had outstanding $470 million of notes payable consisting principally of commercial paper. For the six months ended June 30, 2002, the average interest rate on notes payable was approximately 1.96%. Certain of the credit agreements to which Exelon, ComEd, PECO and Generation are a party require each of them to maintain a debt to total capitalization ratio of 65% or less (excluding securitization debt and for PECO, excluding the receivable from parent recorded in PECO's shareholders' equity). At June 30, 2002, the debt to total capitalization ratios on that basis for Exelon, ComEd, PECO and Generation were 48%, 46%, 38% and 32%, respectively.

Exelon and its subsidiaries' access to the capital markets, including the commercial paper market, and their financing costs in those markets are dependent on their respective securities ratings. None of Exelon's or its subsidiaries' borrowings is subject to default or prepayment as a result of a downgrading of securities ratings although such a downgrading could increase interest charges under Exelon's bank credit facility. Exelon and its subsidiaries from time to time enter into interest rate swap and other derivatives that require the maintenance of investment grade ratings. Failure to maintain investment grade ratings would allow the counterparty to terminate the derivative and settle the transaction on a net present value basis.

Under the Public Utility Holding Company Act of 1935 (PUHCA) and the Federal Power Act, Exelon, ComEd, PECO and Generation can pay dividends only from retained, undistributed or current earnings. However, an SEC order granted permission to Exelon and ComEd to pay up to $500 million in dividends out of additional paid-in capital, provided that Exelon agreed not to pay dividends out of paid-in capital after December 31, 2002 if its common equity is less than 30% of its total capitalization. At June 30, 2002, Exelon had retained earnings of $1.4 billion, which includes ComEd retained earnings of $382 million, PECO retained earnings of $277 million and Generation retained earnings of $686 million.

Contractual Obligations and Commercial Commitments

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments represent commitments triggered by future events. Exelon's contractual obligations and commercial commitments as of June 30, 2002 were materially unchanged, other than in the normal course of business, from the amounts set forth in the December 31, 2001 Form 10-K except for the following:

- ComEd issued $600 million of First Mortgage Bonds due March 15, 2012, issued $100 million of Illinois Development Finance Authority floating-rate Pollution Control Revenue Refunding Bonds, series 2002, redeemed $100 million of 7.25% Illinois Development Finance Authority Pollution Control Revenue Refunding Bonds, series 1991, redeemed $200 million of First Mortgage Bonds due February 1, 2022, and retired $170 million of transitional trust notes.
- Guarantees increased $300 million primarily related to an increase in the amount of surety bonds required by Enterprises' insurance policies.
- Insured long-term debt increased $100 million related to ComEd's issuance of $100 million in variable rate debt that has been credit enhanced through the purchase of insurance coverage.
- On April 25, 2002 Generation closed the purchase of two generating plants from TXU. The $443 million purchase was funded primarily with commercial paper issued by Exelon.
- On June 26, 2002 Generation agreed to purchase Sithe New England Holdings, LLC (Sithe New England) for $543 million, plus the assumption of non-recourse debt estimated to be approximately $1.2 billion at the date of purchase. The purchase is estimated to close in November 2002, subject to regulatory approval. See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information about the Sithe New England acquisition.
- Purchase obligations increased by $1.2 billion, primarily due to an increase of $2.0 billion in power only purchases partially offset by a $0.8 billion decrease in net capacity purchase commitments. The increase in power only purchases is primarily due to Generation's

agreement to purchase all the energy from Unit No. 1 at Three Mile Island after December 31, 2001 through December 31, 2014. This decrease in net capacity purchase commitments is due primarily to the decision not to exercise the option to purchase 2,684 MWs of capacity from Midwest Generation in 2002 and 2003 as well as the increase in capacity sales under the TXU tolling agreement.

Off Balance Sheet Obligations

Generation owns 49.9% of the outstanding common stock of Sithe and has an option, beginning on December 18, 2002, to purchase the remaining common stock outstanding (Remaining Interest) in Sithe. The purchase option expires on December 18, 2005. In addition, the Sithe stockholders who own in the aggregate the Remaining Interest have the right to require Generation to purchase the Remaining Interest (Put Rights) during the same period in which Generation can exercise its purchase option. At the end of this exercise period, if Generation has not exercised its purchase option and the other Sithe stockholders have not exercised their Put Rights, Generation will have an additional one-time option to purchase shares from the other stockholders in Sithe to bring Generation's ownership in Sithe from the current 49.9% to 50.1% of Sithe's total outstanding common stock.

If Generation exercises its option to acquire the Remaining Interest, or if all the other Sithe stockholders exercise their Put Rights, the purchase price for 70% of the Remaining Interest will be set at fair market value subject to a floor of $430 million and a ceiling of $650 million. The balance of the Remaining Interest will be valued at fair market value subject to a floor of $141 million and a ceiling of $330 million. In either instance, the floor and ceiling will accrue interest from the beginning of the exercise period.

If Generation increases its ownership in Sithe to 50.1% or more, Sithe will become a consolidated subsidiary and Exelon's financial results will include Sithe's financial results from the date of purchase. At June 30, 2002, Sithe had total assets of $4.1 billion and total debt of $2.1 billion, including $1.6 billion of non-recourse project debt of which $1.0 billion is associated with Sithe New England, $0.4 billion of subordinated debt, $49 million of short-term debt, $33 million of capital leases, and excluding $411 million of non-recourse project debt associated with Sithe's equity investments. For the six months ended June 30, 2002, Sithe had revenues of $0.6 billion. As of June 30, 2002, Generation had a $725 million equity investment in Sithe. On June 26, 2002, Generation agreed to purchase Sithe New England for $543 million plus the assumption of approximately $1.2 billion of non-recourse project debt, which is expected to be outstanding at the time of the closing of the purchase. Generation expects to close the purchase of Sithe New England in November 2002, subject to regulatory approval.

Additionally, the debt on the books of Exelon's unconsolidated equity investments and joint ventures is not reflected on Exelon's Consolidated Balance Sheets. Total investee debt, at June 30, 2002, including the debt of Sithe described in the preceding paragraph, is currently estimated to be $2.3 billion ($1.2 billion based on Exelon's ownership interest of the investments).

Generation and British Energy plc (British Energy), Generation's joint venture partner in AmerGen, have each agreed to provide up to $100 million to AmerGen at any time for operating expenses.

Other Factors

Exelon's costs of providing pension and postretirement benefit plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rate, and the rate of increase in health care costs. The market value of plan assets has been affected by sharp declines in the equity market since the third quarter of 2000. As a result, at December 31, 2002, Exelon could be required to recognize an additional minimum liability as prescribed by FASB SFAS No. 87 "Employers' Accounting for Pensions" and FASB SFAS No. 132 "Employers' Disclosures about Pensions and Postretirement Benefits." The liability would be recorded as a reduction to common equity, and the equity would be restored to the balance sheet in future periods when the fair value of plan assets exceeds the accumulated benefit obligations. The amount of reduction to common equity recorded, if any, will depend upon the asset returns experienced in 2002, but could be material. The recording of this reduction would not affect net income or cash flow in 2002; however, pension cost and cash funding requirements could increase in future years without a substantial recovery in the equity markets.

Generation is a counterparty to Dynegy Inc. (Dynegy) in various energy transactions. In early July 2002, the credit ratings of Dynegy were downgraded by two credit rating agencies to below investment grade. As of July 29, 2002, Generation had a net receivable from Dynegy of less than $5 million, and consistent with the terms of the existing credit arrangement, has requested collateral in support of this receivable. Generation also has credit risk associated with Dynegy through Generation's equity investment in Sithe. Sithe is a 60% owner of the Independence generating station, a 1,040 MW gas-fired qualified facility that has an energy only long-term tolling arrangement with Dynegy, with a related financial swap arrangement. As of June 30, 2002, Sithe had recognized an asset on its balance sheet related to the fair value of the financial swap agreement with Dynegy that is marked-to-market under the terms of SFAS No. 133. If Dynegy is unable to fulfill the terms of this agreement, Sithe would be required to write-off the fair value asset, which Generation estimates would result in an approximate $15 million reduction in its equity earnings from Sithe, based on Generation's current 49.9% investment ownership in Sithe. Additionally, the future economic value of Sithe's investment in the Independence Station and AmerGen's purchased power arrangement with Illinois Power, a subsidiary of Dynegy, could be impacted by events related to Dynergy's financial condition.

COMMONWEALTH EDISON COMPANY

GENERAL

ComEd operates in a single business segment, Energy Delivery, and its operations consist of its retail electricity distribution and transmission business in northern Illinois.

RESULTS OF OPERATIONS

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001

Significant Operating Trends - ComEd

	Three Months Ended June 30, 2002	2001	Variance	% Change
OPERATING REVENUES	$ 1,481	$1,530	$ (49)	(3.2%)
OPERATING EXPENSES				
Purchased Power	553	586	(33)	(5.6%)
Operating and Maintenance	220	248	(28)	(11.3%)
Depreciation and Amortization	133	168	(35)	(20.8%)
Taxes Other Than Income	73	69	4	5.8%
Total Operating Expense	979	1,071	(92)	(8.6%)
OPERATING INCOME	502	459	43	9.4%
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(127)	(143)	16	(11.2%)
Distributions on Company-Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely the Company's Subordinated Debt Securities	(7)	(7)	--	--
Other, net	14	22	(8)	(36.4%)
Total Other Income and Deductions	(120)	(128)	8	(6.3%)
INCOME BEFORE INCOME TAXES	382	331	51	15.4%
INCOME TAXES	151	149	2	1.3%
NET INCOME	$ 231	$ 182	$ 49	26.9%

Net Income

Net income increased $49 million, or 27% for the three months ended June 30, 2002. Net income was impacted by $43 million increase in operating income and by a lower effective income tax rate.

Operating Revenues

ComEd's electric sales statistics are as follows:

Retail Deliveries - (in GWh)	For the three months ended June 30, 2002	2001	% Change
Bundled Deliveries (1)			
Residential	5,862	5,232	12.0%
Small Commercial & Industrial	5,600	5,803	(3.5%)
Large Commercial & Industrial	2,122	2,748	(22.8%)
Public Authorities & Electric Railroads	1,685	1,891	(10.9%)
	15,269	15,674	(2.6%)
Unbundled Deliveries (2)			
ARES			
Small Commercial & Industrial	1,177	645	82.5%
Large Commercial & Industrial	1,622	1,251	29.7%
Public Authorities & Electric Railroads	181	93	94.6%
	2,980	1,989	49.8%
PPO			
Small Commercial & Industrial	839	798	5.1%
Large Commercial & Industrial	1,392	1,518	(8.3%)
Public Authorities & Electric Railroads	274	326	(16.0%)
	2,505	2,642	(5.2%)
Total Unbundled Deliveries	5,485	4,631	18.4%
Total Retail Deliveries	20,754	20,305	2.2%

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy.

(2) Unbundled service reflects customers electing to receive electric generation service from an ARES or the PPO.

Electric Revenue	For the three months ended June 30, 2002	2001	Variance	% Change
Bundled Revenues (1)				
Residential	$ 523	$ 502	$ 21	4.2%
Small Commercial & Industrial	445	467	(22)	(4.7%)
Large Commercial & Industrial	116	144	(28)	(19.4%)
Public Authorities & Electric Railroads	102	109	(7)	(6.4%)
	1,186	1,222	(36)	(3.0%)
Unbundled Revenues (2)				
ARES				
Small Commercial & Industrial	30	13	17	130.8%
Large Commercial & Industrial	32	21	11	52.4%
Public Authorities & Electric Railroads	5	1	4	n.m.
	67	35	32	91.4%
PPO				
Small Commercial & Industrial	55	53	2	3.8%
Large Commercial & Industrial	76	86	(10)	(11.6%)
Public Authorities & Electric Railroads	17	19	(2)	(10.5%)
	148	158	(10)	(6.3%)
Total Unbundled Revenues	215	193	22	11.4%
Total Electric Retail Revenues	1,401	1,415	(14)	(1.0%)
Wholesale and Miscellaneous Revenue (3)	80	115	(35)	(30.4%)
Total Electric Revenue	$ 1,481	$1,530	$ (49)	(3.2%)

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy.
(2) Revenue from customers choosing an ARES includes a distribution charge and a CTC charge. Transmission charges received from ARES are included in wholesale and miscellaneous revenue. Revenues from customers choosing the PPO includes an energy charge at market rates, transmission, and distribution charges and a CTC charge.
(3) Wholesale and miscellaneous revenues include sales to ARES, transmission revenue, sales to municipalities and other wholesale energy sales.
n.m. - not meaningful

The changes in electric retail revenues for the three months ended June 30, 2002, as compared to the three months ended June 30, 2001, are attributable to the following:

	Variance
Weather	$ 40
Rate Changes	(27)
Customer Choice	(39)
Other Effects	12
Electric Retail Revenue	$ (14)

o Weather. The demand for electricity is impacted by weather conditions. Very warm weather in summer months and very cold weather in other months is referred to as "favorable weather conditions", because these weather conditions result in increased sales of electricity. Conversely, mild weather reduces demand.

The weather impact for the three months ended June 30, 2002 was favorable compared to the three months ended June 30, 2001 as a result of warmer summer weather in the second quarter of 2002 as compared to the second quarter of 2001. Cooling degree-days increased 29% in the three months ended June 30, 2002 compared to the three months ended June 30, 2001.

- Rate Changes. The decrease attributable to rate changes reflects a 5% residential rate reduction, effective October 1, 2001, required by the Illinois restructuring legislation.
- Customer Choice. All ComEd customers have the choice to purchase energy from other suppliers. This choice generally does not impact the volume of deliveries, but affects revenue collected from customers related to energy supplied by ComEd. On May 1, 2002, all ComEd residential customers were eligible to choose their supplier of electricity, however, as of June 30, 2002, no alternative electric supplier has sought approval from the ICC and no electric utilities have chosen to enter the ComEd residential market for the supply of electricity.

  The decrease in revenues reflects customers in Illinois electing to purchase energy from an ARES or the PPO. As of June 30, 2002, approximately 22,600 retail customers had elected to purchase energy from an ARES or the ComEd PPO, an increase from 14,000 customers at June 30, 2001. The MWhs delivered to such customers increased from approximately 4.6 million for the three months ended June 30, 2001 to 5.5 million for the three months ended June 30, 2002, or approximately a 20% increase from the previous year.
- Other Effects. A strong housing construction market in Chicago contributed to residential and small commercial and industrial customer volume growth, partially offset by the unfavorable impact of a slower economy on large commercial and industrial customers.

On July 19, 2002, ComEd filed a request with the ICC to revise the Provider of Last Resort (POLR) obligation in Illinois. ComEd is seeking permission from the ICC to limit the availability by June 2006 of Rate 6L for 370 of ComEd's largest energy customers with demands of at least three MWs, totaling approximately 2,500 MWs. Rate 6L is a bundled fixed rate offered to large customers including heavy industrial plants, large office buildings, government facilities and a variety of other businesses. The ICC has 120 days to act on the filing or it will be deemed approved.

The reduction in wholesale revenue for the three months ended June 30, 2002 as compared to the three months ended June 30, 2001 was due primarily to a $10 million decrease in off-system sales due to the expiration of wholesale contracts that were offered by ComEd from June 2000 to May 2001 to support the open access program in Illinois and a $15 million reversal of reserve in 2001 for revenue refunds related to certain of ComEd's municipal customers as a result of a favorable FERC ruling.

Purchased Power Expense

Purchased power expense decreased $33 million, or 6% for the three months ended June 30, 2002. The decrease in purchased power expense was primarily attributable to a $29 million decrease as a result of customers choosing to purchase energy from an ARES, an $8 million decrease due to the expiration of the wholesale contracts offered by ComEd to support the open access program in Illinois, a $5 million decrease related to a reduction in the average purchase price of energy and a $5 million decrease due to the effects of the slower economy on the large commercial and industrial customers partially offset by a $15 million increase due to favorable weather conditions.

Operating and Maintenance Expense

Operating and maintenance (O&M) expense decreased $28 million, or 11%, for the three months ended June 30, 2002. The decrease in O&M expense was primarily attributable to an $11 million decrease in bad debt expense due to a revised estimate of the reserve for uncollectible accounts, a $4 million decrease in corporate allocations, and a $9 million decrease in repairs of distribution systems damaged by others and storm restoration.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $35 million, or 21%, for the three months ended June 30, 2002. This decrease is primarily due to the discontinuation of goodwill amortization effective January 1, 2002 upon the adoption of SFAS No. 142 partially offset by increased depreciation based on higher property, plant and equipment balances.

As required by the Illinois Restructuring Act, a notification filing was made with the ICC to reflect lower depreciation rates effective July 1, 2002. No ICC approval is required for the new rates to take effect. The anticipated annual reduction in depreciation expense is estimated to be approximately $100 million.

Taxes Other Than Income

Taxes other than income remained consistent from period to period.

Interest Charges

Interest charges consist of interest expense and distributions on Company-Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts. Interest charges decreased $16 million, or 11%, for the three months ended June 30, 2002. The decrease in interest charges was primarily attributable to the impact of lower interest rates for the three months ended June 30, 2002 as compared to the three months ended June 30, 2001, the early retirement of the $196 million of First Mortgage Bonds in November of 2001 and the retirement of $340 million in transitional trust notes since June 2001.

Other Income and Deductions

Other income and deductions, excluding interest charges, decreased $8 million or 36%, for the three months ended June 30, 2002. The decrease was primarily attributable to $2 million in intercompany interest income relating to the $400 million receivable from PECO which was repaid during second quarter 2001 and a $7 million reduction in intercompany interest income from Unicom Investment Inc., reflecting lower interest rates.

Income Taxes

The effective income tax rate was 39.5% for the three months ended June 30, 2002, compared to 45.0% for the three months ended June 30, 2001. The decrease in the effective tax rate was primarily attributable to the discontinuation of goodwill amortization as of January 1, 2002, which was not deductible for income tax purposes.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001

Significant Operating Trends - ComEd

	Six Months Ended June 30, 2002	2001	Variance	% Change
OPERATING REVENUES	$ 2,796	$2,976	$ (180)	(6.1%)
OPERATING EXPENSES				
Purchased Power	1,091	1,195	(104)	(8.7%)
Operating and Maintenance	457	466	(9)	(1.9%)
Depreciation and Amortization	268	334	(66)	(19.8%)
Taxes Other Than Income	146	141	5	3.6%
Total Operating Expense	1,962	2,136	(174)	(8.2%)
OPERATING INCOME	834	840	(6)	(0.7%)
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(252)	(284)	32	(11.3%)
Distributions on Company-Obligated Mandatorily Redeemable Preferred Securities of Subsidiary Trusts Holding Solely the Company's Subordinated Debt Securities	(15)	(15)	--	--
Other, net	29	59	(30)	(50.9%)
Total Other Income and Deductions	(238)	(240)	2	(0.8%)
INCOME BEFORE INCOME TAXES	596	600	(4)	(0.7%)
INCOME TAXES	236	271	(35)	(12.9%)
NET INCOME	$ 360	$ 329	$ 31	9.4%

Net Income

Net income increased $31 million, or 9% for the six months ended June 30, 2002. Net income was impacted by a $35 million decrease in income taxes due to a lower effective income tax rate offset in part by a decrease in operating income.

Operating Revenues

ComEd's electric sales statistics are as follows:

Retail Deliveries - (in GWh)	For the six months ended June 30, 2002	2001	% Change
Bundled Deliveries (1)			
Residential	12,271	11,538	6.4%
Small Commercial & Industrial	11,049	11,678	(5.4%)
Large Commercial & Industrial	4,078	5,638	(27.7%)
Public Authorities & Electric Railroads	3,486	3,901	(10.6%)
	30,884	32,755	(5.7%)
Unbundled Deliveries (2)			
ARES			
Small Commercial & Industrial	2,181	1,107	97.0%
Large Commercial & Industrial	3,008	2,414	24.6%
Public Authorities & Electric Railroads	319	136	134.6%
	5,508	3,657	50.6%
PPO			
Small Commercial & Industrial	1,602	1,622	(1.2%)
Large Commercial & Industrial	2,703	2,876	(6.0%)
Public Authorities & Electric Railroads	517	584	(11.5%)
	4,822	5,082	(5.1%)
Total Unbundled Deliveries	10,330	8,739	18.2%
Total Retail Deliveries	41,214	41,494	(0.7%)

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy.

(2) Unbundled service reflects customers electing to receive electric generation service from an ARES or the PPO.

Electric Revenue	For the six months ended June 30, 2002	2001	Variance	% Change
Bundled Revenues (1)				
Residential	$ 1,041	$ 1,035	$ 6	0.6%
Small Commercial & Industrial	836	880	(44)	(5.0%)
Large Commercial & Industrial	218	280	(62)	(22.1%)
Public Authorities & Electric Railroads	194	216	(22)	(10.2%)
	2,289	2,411	(122)	(5.1%)
Unbundled Revenues (2)				
ARES				
Small Commercial & Industrial	43	26	17	65.4%
Large Commercial & Industrial	41	48	(7)	(14.6%)
Public Authorities & Electric Railroads	7	2	5	n.m.
	91	76	15	19.7%
PPO				
Small Commercial & Industrial	98	90	8	8.9%
Large Commercial & Industrial	140	146	(6)	(4.1%)
Public Authorities & Electric Railroads	29	31	(2)	(6.5%)
	267	267	--	--
Total Unbundled Revenues	358	343	15	4.4%
Total Electric Retail Revenues	2,647	2,754	(107)	(3.9%)
Wholesale and Miscellaneous Revenue (3)	149	222	(73)	(32.9%)
Total Electric Revenue	$ 2,796	$ 2,976	$ (180)	(6.1%)

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy and the delivery cost of the transmission and the distribution of the energy.
(2) Revenue from customers choosing an ARES includes a distribution charge and a CTC charge. Transmission charges received from ARES are included in wholesale and miscellaneous revenue. Revenues from customers choosing the PPO includes an energy charge at market rates, transmission, and distribution charges and a CTC charge.
(3) Wholesale and miscellaneous revenues include sales to ARES, transmission revenue, sales to municipalities and other wholesale energy sales.

The changes in electric retail revenues for the six months ended June 30, 2002, as compared to the six months ended June 30, 2001, are attributable to the following:

	Variance
Weather	$ (13)
Rate Changes	(54)
Customer Choice	(78)
Other Effects	38
Retail Revenue	$ (107)

o Weather. The weather impact for the six months ended June 30, 2002 was unfavorable compared to the six months ended June 30, 2001 as a result of warmer winter weather partially offset by warmer summer weather in 2002 compared to 2001. Heating degree-days decreased 6% and were partially offset by a 29% increase in cooling degree-days in the six months ended June 30, 2002 compared to the six months ended June 30, 2001
o Rate Changes. The decrease attributable to rate changes reflects a 5% residential rate reduction, effective October 1, 2001, required by the Illinois restructuring legislation.

- Customer Choice. The decrease in revenues reflects customers in Illinois electing to purchase energy from an ARES or the PPO. As of June 30, 2002, approximately 22,600 retail customers had elected to purchase energy from an ARES or the ComEd PPO, an increase from 14,000 customers at June 30, 2001. The MWhs delivered to such customers increased from approximately 8.7 million for the six months ended June 30, 2001 to 10.3 million for the six months ended June 30, 2002, approximately a 20% increase from the previous year.
- Other Effects. A strong housing construction market in Chicago contributed to residential and small commercial and industrial customer volume growth, partially offset by the unfavorable impact of a slower economy on large commercial and industrial customers.

The reduction in wholesale revenue for the six months ended June 30, 2002 as compared to the six months ended June 30, 2001 was due primarily to a $38 million decrease in off-system sales due to the expiration of wholesale contracts that were offered by ComEd from June 2000 to May 2001 to support the open access program in Illinois, a $15 million reversal of reserve for revenue refunds in 2001 related to certain of ComEd's municipal customers as a result of a favorable FERC ruling, and $20 million of other miscellaneous revenue.

Purchased Power Expense

Purchased power expense decreased $104 million, or 9% for the six months ended June 30, 2002. The decrease in purchased power expense was primarily attributable to a $5 million decrease due to unfavorable weather conditions, a $62 million decrease as a result of customers choosing to purchase energy from an ARES, and a $34 million decrease due to the expiration of the wholesale contracts offered by ComEd to support the open access program in Illinois.

Operating and Maintenance Expense

O&M expense remained relatively consistent from period to period.

Depreciation and Amortization Expense

Depreciation and amortization expense decreased $66 million, or 20%, for the six months ended June 30, 2002. This decrease is primarily due to the discontinuation of goodwill amortization effective January 1, 2002 upon the adoption of SFAS No. 142 partially offset by increased depreciation based on higher property plant and equipment balances.

Taxes Other Than Income

Taxes other than income remained consistent from period to period.

Interest Charges

Interest charges decreased $32 million, or 11%, for the six months ended June 30, 2002. The decrease in interest charges was primarily attributable to the impact of lower interest rates for the six months ended June 30, 2002 as compared to the six months ended June 30, 2001, the early retirement of the $196 million of First Mortgage Bonds in November of 2001 and the retirement of $340 million in transitional trust notes since June 2001.

Other Income and Deductions

Other income and deductions, excluding interest charges, decreased $30 million, or 51%, for the six months ended June 30, 2002. The decrease was primarily attributable to $8 million in intercompany interest income relating to the $400 million receivable from PECO which was repaid during the second quarter of 2001, and a $22 million reduction in intercompany interest income from Unicom Investment Inc., reflecting lower interest rates.

Income Taxes

The effective income tax rate was 39.6% for the six months ended June 30, 2002, compared to 45.2% for the six months ended June 30, 2001. The decrease in the effective tax rate was primarily attributable to the discontinuation of goodwill amortization as of January 1, 2002, which was not deductible for income tax purposes.

LIQUIDITY AND CAPITAL RESOURCES

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing including the issuance of commercial paper. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and the general business condition of ComEd and the utility industry. Capital resources are used primarily to fund ComEd's capital requirements, including construction, repayments of maturing debt, and the payment of common stock dividends.

Cash Flows from Operating Activities

Cash flows provided by operations were $740 million for the six months ended June 30, 2002 compared to $705 million for the six months ended June 30, 2001. The increase in cash flows in 2002 was primarily attributable to a $107 million increase in other operating activities partially offset by a $67 million decrease in working capital. ComEd's future cash flows will depend upon the ability to achieve cost savings in operations, the impact of the economy, weather, and customer choice on its revenues. Although the amounts may vary from period to period as a result of uncertainties inherent in the business, ComEd expects to continue to provide a reliable and steady source of internal cash flow from operations for the foreseeable future.

Cash Flows from Investing Activities

Cash flows used in investing activities were $352 million for the six months ended June 30, 2002 compared to $58 million for the six months ended June 30, 2001. The increase in cash flows used in investing activities in 2002 was primarily attributable to the paydown of the $400 million outstanding receivable with PECO in the second quarter of 2001 partially offset by an $87 million decrease in capital expenditures. ComEd's investing activities for the six months ended June 30, 2002 were funded primarily through operating activities.

ComEd estimated that it will spend approximately $781 million in total capital expenditures for 2002. Approximately two thirds of the budgeted 2002 expenditures are for continuing efforts to further improve the reliability of its transmission and distribution systems. The remaining one third is for capital additions to support new business and customer growth. ComEd anticipates that it will obtain financing, when necessary, through borrowings, the issuance of preferred securities, or capital contributions from Exelon. ComEd's proposed capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Cash Flows from Financing Activities

Cash flows used in financing activities were $57 million for the six months ended June 30, 2002 as compared to $322 million for the six months ended June 30, 2001. Cash flows used in financing activities were primarily attributable to debt service and payments of dividends to Exelon. ComEd's debt financing activities for the six months ended June 30, 2002 reflected the issuance of $600 million in First Mortgage Bonds, the issuance of $100 million of 7.25% Illinois Development Finance Authority floating-rate Pollution Control Revenue Refunding Bonds, the retirement of $170 million of transitional trust notes, the early retirement of $200 million in First Mortgage Bonds with available cash, and the redemption of $100 million of Illinois Development Finance Authority Pollution Control Revenue Refunding Bonds. For the six months ended June 30, 2001, ComEd's debt financing activities reflected the retirement of $170 million of transitional trust notes. ComEd paid a $235 million dividend to Exelon during the six months ended June 30, 2002 compared to a $148 million dividend for the six months ended June 30, 2001.

Credit Issues

ComEd meets its short-term liquidity requirements primarily through the issuance of commercial paper, borrowings under bank credit facilities and borrowings from the Exelon intercompany money pool. ComEd, along with Exelon, PECO and Generation entered into a $1.5 billion unsecured 364-day revolving credit facility on December 12, 2001 with a group of banks. ComEd has a $300 million sublimit under the credit facility and expects to use the credit facility principally to support its $300 million commercial paper program. This credit facility requires ComEd to maintain a debt to total capitalization ratio of 65% or less (excluding transitional trust notes). At June 30, 2002, ComEd's debt to total capitalization ratio on that basis was 46%. At June 30, 2002, ComEd had no short-term borrowings.

ComEd's access to the capital markets, including the commercial paper market, and its financing costs in those markets are dependent on its securities ratings. None of ComEd's borrowings are subject to default or prepayment as a result of a downgrading of securities ratings although such a downgrading could increase interest charges under certain bank credit facilities. ComEd from time to time enters into interest rate swaps and other derivatives that require the maintenance of investment grade ratings. Failure to maintain investment grade ratings would allow the counterparty to terminate the derivative and settle the transaction on a net present value basis.

At June 30, 2002, ComEd's capital structure, excluding the deduction from shareholders' equity of the $875 million receivable from Exelon, consisted of 52% long-term debt, 46% of common stock, and 2% of preferred securities of subsidiaries. Long-term debt included $2.1 billion of transitional trust notes constituting obligations of certain consolidated special purpose entities representing 16% of capitalization.

Under PUHCA and the Federal Power Act, ComEd can only pay dividends from retained or current earnings. However, the SEC has authorized ComEd to pay up to $500 million in dividends out of additional paid-in capital, provided ComEd may not pay dividends out of paid-in capital after December 31, 2002 if its common equity is less than 30% of its total capitalization (including transitional trust notes). At June 30, 2002, ComEd had retained earnings of $382 million.

Contractual Obligations and Commercial Commitments

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments represent commitments triggered by future events. ComEd's contractual obligations and commercial commitments as of June 30, 2002 were materially unchanged, other than in the normal course of business, from the amounts as set forth in the December 31, 2001 Form 10-K except for the issuance of $600 million of First Mortgage Bonds due March 15, 2012, the issuance of $100 million of Illinois Development Finance Authority floating-rate Pollution Control Revenue Refunding Bonds, Series 2002, the redemption of $100 million of 7.25% Illinois Development Finance Authority Pollution Control Revenue Refunding Bonds, Series 1991, the redemption of $200 million of First Mortgage Bonds due February 1, 2022, and the retirement of $170 million in transitional trust notes.

PECO ENERGY COMPANY

GENERAL

PECO operates in a single business segment, Energy Delivery, and its operations consist of its retail electricity distribution and transmission business in southeastern Pennsylvania and its natural gas distribution business in the Pennsylvania counties surrounding the City of Philadelphia.

RESULTS OF OPERATIONS

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001

	Three Months Ended June 30, 2002	2001	Variance	% Change
OPERATING REVENUES	$ 995	$ 906	$ 89	9.8%
OPERATING EXPENSES				
Purchased Power	405	315	90	28.6%
Fuel	53	79	(26)	(32.9%)
Operating and Maintenance	131	126	5	4.0%
Depreciation and Amortization	109	99	10	10.1%
Taxes Other Than Income	63	41	22	53.7%
Total Operating Expense	761	660	101	15.3%
OPERATING INCOME	234	246	(12)	(4.9%)
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(92)	(119)	27	(21.4%)
Distributions on Company-Obligated Mandatorily Redeemable Preferred Securities of a Partnership which holds Solely Subordinated Debentures of the Company	(2)	(2)	--	--
Other, net	2	4	(2)	(50.0%)
Total Other Income and Deductions	(92)	(117)	25	(21.4%)
INCOME BEFORE INCOME TAXES	142	129	13	10.1%
INCOME TAXES	49	44	5	11.4%
NET INCOME	93	85	8	9.4%
Preferred Stock Dividends	(2)	(3)	1	(33.3%)
NET INCOME ON COMMON STOCK	$ 91	$ 82	$ 9	11.0%

Net income on common stock increased $9 million, or 11% for the quarter ended June 30, 2002 as compared to the same 2001 period. The increase was a result of higher additional volume, favorable rate adjustments and lower interest expense on debt partially offset by increased depreciation and amortization expense.

PECO's electric sales statistics are as follows:

Deliveries - (in GWh)	For the three months ended June 30, 2002	2001	% Change
Bundled Deliveries (1)			
Residential	2,115	1,673	26.4%
Small Commercial & Industrial	1,881	1,312	43.4%
Large Commercial & Industrial	3,927	3,172	23.8%
Public Authorities & Electric Railroads	200	181	10.5%
	8,123	6,338	28.2%
Unbundled Deliveries (2)			
Residential	557	848	(34.3%)
Small Commercial & Industrial	2	524	(99.6%)
Large Commercial & Industrial	13	732	(98.2%)
Public Authorities & Electric Railroads	--	2	(100.0%)
	572	2,106	(72.8%)
Total Retail Deliveries	8,695	8,444	3.0%

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy, the delivery cost of the transmission and distribution of the energy and a CTC charge.
(2) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier.

Electric Revenue	For the three months ended June 30, 2002	2001	Variance	%Change
Bundled Revenue (1)				
Residential	$ 278	$ 222	$ 56	25.2%
Small Commercial & Industrial	224	157	67	42.7%
Large Commercial & Industrial	288	224	64	28.6%
Public Authorities & Electric Railroads	19	17	2	11.8%
	809	620	189	30.5%
Unbundled Revenue (2)				
Residential	42	67	(25)	(37.3%)
Small Commercial & Industrial	--	28	(28)	(100.0%)
Large Commercial & Industrial	1	19	(18)	(94.7%)
Public Authorities & Electric Railroads	--	--	--	--
	43	114	(71)	(62.3%)
Total Electric Retail Revenues	852	734	118	16.1%
Wholesale and Miscellaneous Revenue (3)	59	60	(1)	(1.7%)
Total Electric Revenue	$ 911	$ 794	$ 117	14.7%

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy, the delivery cost of the transmission and distribution of the energy and a CTC charge.
(2) Revenue from customers receiving generation from an alternate supplier includes a distribution charge and a CTC charge.
(3) Wholesale and miscellaneous revenues include sales, transmission revenue, sales to municipalities and other wholesale energy sales.

The changes in electric retail revenues for the quarter ended June 30, 2002, as compared to the same 2001 period, are as follows:

	Variance
Customer Choice	$ 85
Rate Changes	13
Weather	1
Other Effects	19
Electric Retail Revenue	$ 118

- Customer Choice. All PECO customers have choice to purchase energy from other suppliers. This choice generally does not impact kWh deliveries, but reduces revenue collected from customers because they are not obtaining generation supply from PECO.

  As of June 30, 2002, the customer load served by alternate suppliers was 991 MW or 12.8% as compared to 1,102 MW or 14.5% as of June 30, 2001. For the quarter ended June 30, 2002, the percent of PECO's total retail deliveries for which PECO was the electric supplier was 93.4% in 2002, an 18.3% increase as compared to 75.1% in 2001. As of June 30, 2002, the number of customers served by alternate suppliers was 308,866 or 20.2% as compared to June 30, 2001 of 400,972 or 26.4%. The increases in the customer load and the percentage of MWh served by PECO, and the decrease in the number of customers served by alternative suppliers primarily resulted from customers selecting or returning to PECO as their electric generation supplier.

  In February 2002, New Power Company (New Power) notified PECO of its intent to withdraw from providing Competitive Default Service (CDS) to approximately 180,000 residential customers. As a result of that withdrawal, those CDS customers were returned to PECO in the second quarter of 2002. Pursuant to a tariff filing approved by the Pennsylvania Public Utility Commission (PUC), PECO will serve those returned customers at the discount energy rates on generation provided for under the original New Power CDS Agreement for the remaining term of that contract. Subsequently, in the second quarter of 2002, New Power also advised PECO it planned to withdraw from serving all of its customers in Pennsylvania, including approximately 15,000 non-CDS PECO customers, and to return those customers to PECO in September.
- Rate Changes. The increase in revenues attributable to rate changes primarily reflects a $13 million increase due to an increase in the gross receipts tax rate effective January 1, 2002.

  As permitted by the Pennsylvania Electric Competition Act, the Pennsylvania Department of Revenue has calculated a 2002 Revenue Neutral Reconciliation (RNR) adjustment to the gross receipts tax rate in order to neutralize the impact of electric restructuring on its tax revenues. The RNR adjustment increases the gross receipts tax rate, which will increase PECO's annual revenues and tax obligations by approximately $50 million in 2002. In January 2002, the PUC approved the adjustment to the gross receipts tax rate, which was implemented effective January 1, 2002. The RNR adjustment is under appeal.
- Weather. The demand for electricity and gas services is impacted by weather conditions. Very warm weather in summer months and very cold weather in other months is referred to as "favorable weather conditions", because these weather conditions result in increased sales of electricity and gas. Conversely, mild weather reduces demand.

The weather impact was favorable compared to the prior year as a result of warmer summer weather.

- Other Effects. Other items affecting revenue during the quarter ended June 30, 2002 include:
  - Volume. Exclusive of weather impacts, higher delivery volume affected PECO's revenue by $24 million compared to the same 2001 period.
  - Other. The payment of $7 million to Generation related to nuclear decommissioning cost recovery under an agreement effective September 2001, which reduced PECO's revenue compared to the prior year.

PECO's gas sales statistics for the quarter ended June 30, 2002 as compared to the same 2001 period are as follows:

	For the three months ended June 30,		
	2002	2001	Variance
Deliveries in mmcf	14,286	13,781	505
Revenue	$84	$ 112	$ (28)

The changes in gas revenue for the quarter ended June 30, 2002, as compared to the same 2001 period, are as follows:

(in millions)	Variance
Rate Changes	$ (28)
Weather	--
Volume	(1)
Other	1
Gas Revenue	$ (28)

- Rate Changes. The unfavorable variance in rates is attributable to an adjustment of the purchased gas cost recovery by the PUC effective in December 2001. The average rate per million cubic feet for all customers for the quarter ended June 30, 2002 was 28% lower than the same 2001 period. PECO's gas rates are subject to periodic adjustments by the PUC designed to recover or refund the difference between actual cost of purchased gas and the amount included in base rates and to recover or refund increases or decreases in certain state taxes not recovered in base rates.
- Weather. The weather impact was neutral during the quarter ended June 30, 2002 compared to the same 2001 period.
- Volume. Exclusive of weather impact, delivery volume was consistent for the quarter ended June 30, 2002 compared to the same 2001 period.

Purchased Power and Fuel Expense

Purchased power and fuel expense for the quarter ended June 30, 2002 increased $64 million as compared to the same 2001 period. The increase in fuel and purchased power expense was primarily attributable to $73 million from customers in Pennsylvania selecting or returning to PECO as their electric generation supplier, $9 million primarily attributable to higher delivery volume and higher PJM ancillary charges of $8 million. These increases were partially offset by $28 million from lower gas prices.

Operating and Maintenance Expense

O&M expense for the quarter ended June 30, 2002 increased $5 million, or 4%, as compared to the same 2001 period. The increase in O&M expense was primarily attributable to $5 million related to the deployment of automated meter reading technology and $3 million related to an increased allocation of corporate expense.

Depreciation and Amortization Expense

Depreciation and amortization expense for the quarter ended June 30, 2002 increased $10 million, or 10%, as compared to the same 2001 period. The increase was primarily attributable to $9 million of additional amortization of PECO's CTC and an increase of $1 million related to depreciation expense associated with additional plant in service. The additional amortization of the CTC is in accordance with PECO's original settlement under the Pennsylvania Competition Act.

Taxes Other Than Income

Taxes other than income for the quarter ended June 30, 2002 increased $22 million, or 54%, as compared to the same 2001 period. The increase was primarily attributable to additional gross receipts tax related to additional revenues and an increase in the gross receipts tax rate on electric revenue effective January 1, 2002.

Interest Charges

Interest charges consist of interest expense and distributions on Company-Obligated Mandatorily Redeemable Preferred Securities of a Partnership (COMRPS). Interest charges decreased $27 million, or 21% in the quarter ended June 30, 2002 as compared to the same 2001 period. The decrease was primarily attributable to lower interest expense on long-term debt of $22 million as a result of principal payments and lower interest rates and interest expense related to a loan from an affiliate in 2001 of $2 million.

Other Income and Deductions

Other income and deductions excluding interest charges remained consistent in the quarter ended June 30, 2002 as compared to the same 2001 period.

Income Taxes

The effective tax rate was substantially unchanged at 34.5% for the quarter ended June 30, 2002 as compared to 34.1% for the same 2001 period.

Preferred Stock Dividends

Preferred stock dividends for the quarter ended June 30, 2002 were consistent as compared to the same 2001 period.

Six Months Ended June 30, 2002 Compared to Six Months Ended June 30, 2001

	Six Months Ended June 30,			
	2002	2001	Variance	% Change
OPERATING REVENUES	$ 2,015	$1,957	$ 58	3.0%
OPERATING EXPENSES				
Purchased Power	756	598	158	26.4%
Fuel	188	284	(96)	(33.8%)
Operating and Maintenance	267	258	9	3.5%
Depreciation and Amortization	221	200	21	10.5%
Taxes Other Than Income	122	84	38	45.2%
Total Operating Expense	1,554	1,424	130	9.1%
OPERATING INCOME	461	533	(72)	(13.5%)
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(187)	(227)	40	(17.6%)
Distributions on Company-Obligated Mandatorily Redeemable Preferred Securities of a Partnership which holds Solely Subordinated Debentures of the Company	(5)	(5)	--	--
Other, net	2	18	(16)	(88.9%)
Total Other Income and Deductions	(190)	(214)	24	(11.2%)
INCOME BEFORE INCOME TAXES	271	319	(48)	(15.0%)
INCOME TAXES	90	112	(22)	(19.6%)
NET INCOME	181	207	(26)	(12.6%)
Preferred Stock Dividends	(4)	(5)	1	(20.0%)
NET INCOME ON COMMON STOCK	$ 177	$ 202	$ (25)	(12.4%)

Net income on common stock decreased $25 million, or 12% for the six months ended June 30, 2002 as compared to the same 2001 period. The decrease was a result of lower margins due to the unplanned return of certain residential, commercial and industrial customers, milder weather, increased depreciation and amortization expense, partially offset by favorable rate adjustments.

PECO's electric sales statistics are as follows:

Deliveries - (in GWh)	For the six months ended June 30, 2002	2001	% Change
Bundled Deliveries (1)			
Residential	4,171	4,132	0.9%
Small Commercial & Industrial	3,638	2,313	57.3%
Large Commercial & Industrial	7,278	5,703	27.6%
Public Authorities & Electric Railroads	393	374	5.1%
	15,480	12,522	23.6%
Unbundled Deliveries (2)			
Residential	1,348	1,375	(2.0%)
Small Commercial & Industrial	99	1,416	(93.0%)
Large Commercial & Industrial	116	1,921	(94.0%)
Public Authorities & Electric Railroads	--	7	(100.0%)
	1,563	4,719	(66.9%)
Total Retail Deliveries	17,043	17,241	(1.1%)

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy, the delivery cost of the transmission and distribution of the energy and a CTC charge.
(2) Unbundled service reflects customers electing to receive electric generation service from an alternative energy supplier.

Electric Revenue	For the six months ended June 30, 2002	2001	Variance	% Change
Bundled Revenue (1)				
Residential	$ 522	$ 503	$ 19	3.8%
Small Commercial & Industrial	413	264	149	56.4%
Large Commercial & Industrial	532	407	125	30.7%
Public Authorities & Electric Railroads	37	34	3	8.8%
	1,504	1,208	296	24.5%
Unbundled Revenue (2)				
Residential	96	103	(7)	(6.8%)
Small Commercial & Industrial	5	68	(63)	(92.6%)
Large Commercial & Industrial	3	54	(51)	(94.4%)
Public Authorities & Electric Railroads	--	1	(1)	(100.0%)
	104	226	(122)	(54.0%)
Total Electric Retail Revenues	1,608	1,434	174	12.1%
Wholesale and Miscellaneous Revenue (3)	114	116	(2)	(1.7%)
Total Electric Revenue	$ 1,722	$ 1,550	$ 172	11.1%

(1) Bundled service reflects deliveries to customers taking electric service under tariffed rates, which include the cost of energy, the delivery cost of the transmission and distribution of the energy and a CTC charge.
(2) Revenue from customers receiving generation from an alternate supplier includes a distribution charge and a CTC charge.
(3) Wholesale and miscellaneous revenues include sales, transmission revenue, sales to municipalities and other wholesale energy sales.

The changes in electric retail revenues for the six months ended June 30, 2002, as compared to the same 2001 period, are as follows:

	Variance
Customer Choice	$ 165
Rate Changes	39
Weather	(18)
Other Effects	(12)
Electric Retail Revenue	$ 174

- Customer Choice. As of June 30, 2002, the customer load served by alternate suppliers was 991 MW or 12.8% as compared to 1,102 MW or 14.5% as of June 30, 2001. For the six months ended June 30, 2002, the percent of PECO's total retail deliveries for which PECO was the electric supplier was 90.9% in 2002, an 18.2% increase as compared to 72.7% in 2001. As of June 30, 2002, the number of customers served by alternate suppliers was 308,866 or 26.4% as compared to June 30, 2001 of 400,972 or 26.4%. This increase in the customer load and the percentage of MWh served by PECO, and the decrease in the number of customers served by alternative suppliers primarily resulted from customers selecting or returning to PECO as their electric generation supplier.
- Rate Changes. The increase in revenues attributable to rate changes primarily reflects the expiration of a 6% reduction in PECO's electric rates during the first quarter of 2001 and a $26 million increase as a result of the increase in the gross receipts tax rate effective January 1, 2002. These increases are partially offset by the timing of a $60 million rate reduction in effect for 2001 and 2002.
- Weather. The weather impact was unfavorable compared to the prior year primarily as a result of warmer winter weather. Heating degree-days decreased 15% for the six months ended June 30, 2002 compared to the same 2001 period.
- Other Effects. Other items affecting revenue during the six months ended June 30, 2002 include:
  - Volume. Exclusive of weather impacts, higher delivery volume increased PECO's revenue by $7 million compared to the same 2001 period.
  - Other. The payment of $14 million to Generation related to nuclear decommissioning cost recovery under an agreement effective September 2001 which reduced PECO's revenue compared to the prior year and an $11 million settlement of CTCs by a large customer in the first quarter of 2001.

PECO's gas sales statistics for the six months ended June 30, 2002 as compared to the same 2001 period are as follows:

	2002	2001	Variance
Deliveries in mmcf	45,643	48,011	(2,368)
Revenue	$293	$407	$ (114)

The changes in gas revenue for the six months ended June 30, 2002, as compared to the same 2001 period, are as follows:

	Variance
Rate Changes	$ (63)
Weather	(30)
Volume	(22)
Other	1
Gas Revenue	$ (114)

- Rate Changes. The unfavorable variance in rates is attributable to an adjustment of the purchased gas cost recovery by the PUC effective in December 2001. The average rate per million cubic feet for all customers for the six months ended June 30, 2002 was 24% lower than the same 2001 period.
- Weather. The unfavorable weather impact is attributable to warmer winter weather during the six months ended June 30, 2002 as compared to the same 2001 period. Heating degree-days decreased 15% in the six months ended June 30, 2002 compared to the same 2001 period.
- Volume. Exclusive of weather impacts, lower delivery volume affected revenue by $22 million in the six months ended June 30, 2002 compared to the same 2001 period. Total deliveries to retail customers decreased 5% in the six months ended June 30, 2002 compared to the same 2001 period, primarily as a result of slower economic conditions in 2002 offset by increased customer growth.

Purchased Power and Fuel Expense

Purchased power and fuel expense for the six months ended June 30, 2002 increased $62 million as compared to the same 2001 period. The increase in fuel and purchased power expense was primarily attributable to $150 million from customers in Pennsylvania selecting or returning to PECO as their electric generation supplier and higher PJM ancillary charges of $17 million. These increases were partially offset by $63 million from lower gas prices, $30 million as a result of unfavorable weather conditions and $22 million primarily attributable to lower delivery volume primarily related to gas.

Operating and Maintenance Expense

O&M expense for the six months ended June 30, 2002 increased $9 million, or 4%, as compared to the same 2001 period. The increase in O&M expense was primarily attributable to $12 million related to the deployment of automated meter reading technology and $9 million related to an increased allocation of corporate expense. These increases were partially offset by $6 million of incremental storm costs in 2001 and $4 million associated with a write-off of excess and obsolete inventory in 2001.

Depreciation and Amortization Expense

Depreciation and amortization expense for the six months ended June 30, 2002 increased $21 million, or 11%, as compared to the same 2001 period. The increase was primarily attributable to $17 million of additional amortization of PECO's CTC and an increase of $4 million related to depreciation expense associated with additional plant in service. The additional amortization of the CTC is in accordance with PECO's original settlement under the Pennsylvania Competition Act.

Taxes Other Than Income

Taxes other than income for the six months ended June 30, 2002 increased $38 million, or 45%, as compared to the same 2001 period. The increase was primarily attributable to additional gross receipts tax related to additional revenues and an increase in the gross receipts tax rate on electric revenue effective January 1, 2002.

Interest Charges

Interest charges decreased $40 million, or 18% in the six months ended June 30, 2002 as compared to the same 2001 period. The decrease was primarily attributable to lower interest expense on long-term debt of $32 million as a result of principal payments, lower interest rates and an $8 million reduction in interest expense due to lower interest rates on a loan from ComEd in 2001.

Other Income and Deductions

Other income and deductions excluding interest charges decreased $16 million, or 89% in the six months ended June 30, 2002 as compared to the same 2001 period. The decrease in other income and deductions was primarily attributable to lower interest income of $6 million in 2002. The decrease was also attributable to a gain on the settlement of an interest rate swap of $6 million and the favorable settlement of a customer contract of $3 million, both of which occurred in 2001.

Income Taxes

The effective tax rate was 33.2% for the six months ended June 30, 2002 as compared to 35.1% for the same 2001 period. The decrease in the effective tax rate was primarily attributable to a reduction in state income taxes.

Preferred Stock Dividends

Preferred stock dividends for the quarter ended June 30, 2002 were consistent as compared to the same 2001 period.

LIQUIDITY AND CAPITAL RESOURCES

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing including the issuance of commercial paper. PECO's access to external financing at reasonable terms is dependent on its credit ratings and the general business condition of PECO and the utility industry. Capital resources are used primarily to fund construction, repayments of maturing debt and preferred securities and payment of common stock dividends to Exelon.

Cash Flows from Operating Activities

Cash flows provided by operations for the six months ended June 30, 2002 were $468 million compared to $427 million for the six months ended June 30, 2001. The increase in cash flows was primarily attributable to lower payments related to accounts payable of $46 million, higher collection of deferred energy costs as a result of a change in gas rates of $42 million and lower prepaid taxes of $29 million. These increases were partially offset by changes in intercompany receivables and payables of $41 million and deferred income taxes of $32 million. PECO's cash flow from operating activities primarily results from sales of electricity and gas to a stable and diverse base of retail customers at fixed prices. PECO's future cash flows will depend upon the ability to achieve cost savings in operations, and the impact of the economy, weather and customer choice on its revenues. Although the amounts may vary from period to period as a result of the uncertainties inherent in its business, PECO expects that it will continue to provide a reliable and steady source of internal cash flow from operations for the foreseeable future.

Cash Flows from Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2002 were $122 million compared to $87 million for the six months ended June 30, 2001. The increase in cash flows used in investing activities was primarily attributable to an increase in other investing activities. PECO's investing activities during the six months ended June 30, 2002 were funded primarily by operating activities.

PECO's projected capital expenditures for 2002 are $284 million. Approximately one half of the budgeted 2002 expenditures are for capital additions to support customer and load growth and the remainder for additions and upgrades to existing facilities. PECO anticipates that it will obtain financing, when necessary, through borrowings, the issuance of preferred securities, or capital contributions from Exelon. PECO's proposed capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Cash Flows from Financing Activities

Cash flows used in financing activities for the six months ended June 30, 2002 were $306 million compared to $332 million for the six months ended June 30, 2001. Cash flows used in financing activities are primarily attributable to debt service and payment of dividends to Exelon. The change in cash flows used in financing activities is primarily attributable to an increase in commercial paper borrowings of $196 million partially offset by additional dividends paid to Exelon of $69 million, the contribution from Exelon in 2001 of $53 million, additional debt service of $34 million, and proceeds from the settlement of interest rate swap agreements in 2001 of $31 million.

Credit Issues

At June 30, 2002, PECO had outstanding $175 million of notes payable consisting principally of commercial paper. Certain of the credit agreements to which PECO is a party require PECO to maintain a debt to total capitalization ratio of 65% or less, excluding securitization debt and excluding the receivable from parent recorded in PECO's shareholders' equity. At June 30, 2002, the debt to total capitalization ratios on that basis for PECO was 38%.

PECO's access to the capital markets, including the commercial paper market, and its financing costs in those markets are dependent on its securities ratings. None of PECO's borrowings are subject to default or prepayment as a result of a downgrading of securities ratings although such a downgrading could increase interest charges under PECO's bank credit facility. PECO from time to time enters into interest rate swaps that require the maintenance of investment grade ratings. Failure to maintain investment grade ratings would allow the counterparty to terminate the derivative and settle the transaction on a net present value basis.

At June 30, 2002, PECO's capital structure, excluding the deduction from shareholders' equity of the $1.8 billion receivable from Exelon, consisted of 26% common equity, 2% notes payable, 3% preferred stock and COMRPS (which comprised 2% of PECO's total capitalization structure), and 69% long-term debt including transition bonds issued by PECO Energy Transition Trust (PETT). Long-term debt included $4.4 billion of transition bonds representing 52% of capitalization.

Under PUHCA and the Federal Power Act, PECO can pay dividends only from retained or current earnings. At June 30, 2002, PECO had retained earnings of $277 million.

Contractual Obligations and Commercial Commitments

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments represent commitments triggered by future events. PECO's contractual obligations and commercial commitments as of June 30, 2002 were materially unchanged, other than in the normal course of business, from the amounts as set forth in the December 31, 2001 Form 10-K except for an $85 million increase in the amount of surety bonds required by PECO's insurance policies. Approximately one-fourth of the surety bonds expire in the remainder of 2002 and the other three-fourths expire in the two-year period ending December 2004.

EXELON GENERATION COMPANY, LLC

GENERAL

The operations of Generation consist of electric generating facilities, energy marketing operations and equity interests in Sithe and AmerGen.

Generation early adopted the provision of EITF 02-3 that requires revenues and energy costs related to energy trading contracts to be presented on a net basis in the income statement. For comparative purposes, energy costs related to energy trading have been reclassified in prior periods to revenue to conform with the net basis of presentation required by EITF 02-3.

RESULTS OF OPERATIONS

Three Months Ended June 30, 2002 Compared to Three Months Ended June 30, 2001

Significant Operating Trends - Generation

	Three Months Ended June 30,			
	2002	2001	Variance	% Change
OPERATING REVENUES	$ 1,559	$1,583	$ (24)	(1.5%)
OPERATING EXPENSES				
Purchased Power	705	721	(16)	(2.2%)
Fuel	224	230	(6)	(2.6%)
Operating and Maintenance	411	405	6	1.5%
Depreciation	65	75	(10)	(13.3%)
Taxes Other Than Income	41	39	2	5.1%
Total Operating Expense	1,446	1,470	(24)	(1.6%)
OPERATING INCOME	113	113	--	
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(11)	(26)	15	(57.7%)
Equity in Earnings (Losses) of Unconsolidated Affiliates, net	9	13	(4)	(30.8%)
Other, net	24	14	10	71.4%
Total Other Income and Deductions	22	1	21	n.m.
INCOME BEFORE INCOME TAXES	135	114	21	18.4%
INCOME TAXES	51	43	8	18.6%
NET INCOME	$ 84	$ 71	13	18.3%

n.m. - not meaningful

Net Income

Generation's net income increased by $13 million, or 18%, for the three months ended June 30, 2002 compared to the same period in the prior year. Net income was positively impacted by increased revenue from affiliates, increased revenue from the acquisition of two generating plants in April 2002 and reduced depreciation and interest expense, partially offset by depressed wholesale market prices for energy.

Operating Revenues, Net of Purchased Power and Fuel

Operating revenues, net of purchased power and fuel were $630 million for the three months ended June 30, 2002 compared to $632 million for the same period in 2001. The $2 million, or 0.3%, decrease was due to lower market prices for energy, which reduced margins by $46 million during the three months ended June 30, 2002 compared to the same period in 2001.

This decrease was partially offset by a $43 million increase in revenue from affiliates, revenue from two generating plants acquired in April 2002, and lower fuel costs. The average wholesale market prices were $7.00, or 18.6%, lower in 2002 compared to 2001. Generation's average purchased power costs for wholesale operations were $39.96 per MWh for the three months ended June 30, 2002, compared to $45.27 per MWh for the same period in 2001. The decrease in purchase power costs resulted from the decrease in wholesale power market prices. Additionally, revenue for the three months ended June 30, 2002 includes a net trading portfolio loss of $16 million compared to a net $6 million loss for the three months ended June 30, 2001.

For the three months ended June 30, 2002 and 2001, Generation's sales and the supply of these sales excluding the trading portfolio, were as follows:

	Three Months Ended June 30,	
Sales (in GWhs)	2002	2001
Energy Delivery	28,294	28,105
Exelon Energy	1,355	1,415
Market Sales	20,589	18,548
Total Sales	50,238	48,068

	Three Months Ended June 30,	
Supply of Sales (in GWhs)	2002	2001
Nuclear Generation	28,353	28,443
Purchases - non-trading portfolio	18,220	16,392
Fossil and Hydro Generation	3,665	3,233
Total Supply	50,238	48,068

Trading volume was 8,566 GWhs and 454 GWhs for the three months ended June 30, 2002 and 2001, respectively.

Generation's average margins on energy sales for the three months ended June 30, 2002 and 2001 are as follows:

	Three Months Ended June 30,	
($/MWh)	2002	2001
Average Realized Revenue		
Energy Delivery	$ 31.45	$ 30.09
Exelon Energy	44.73	40.11
Market Sales	30.69	37.69
Total Sales - excluding the trading portfolio	31.50	33.32
Average Supply Cost - excluding the trading portfolio	$ 18.79	$ 20.05
Average Margin - excluding the trading portfolio	$ 12.71	$ 13.27

Generation's nuclear fleet, including AmerGen, performed at a capacity factor of 92.1% for the three months ended June 30, 2002 compared to 93.6% for the same period in 2001.

Generation's nuclear fleet's production costs, including AmerGen, for the three months ended June 30, 2002 were $12.54 per MWh compared to $13.02 per MWh for the same period in 2001. The lower capacity factor is primarily due to 72 planned outage days in the three months ended June 30, 2002, versus 31 days in the same period in 2001, including AmerGen. Reduced unit production costs reflect additional generation due to power uprates and lower production costs due to headcount reductions and Exelon's Cost Management Initiative in the three months ended June 30, 2002 as compared to the same period in 2001.

Operating and Maintenance

Operating and maintenance expenses increased $6 million, or 2%, for the three months ended June 30, 2002 compared to the same period in 2001. The increase was primarily due to additional employee benefit costs of $9 million, additional operating costs related to fossil plant outage work and the costs related to the two generating plants acquired in April 2002 of $3 million. These increases were partially offset by $7 million less in nuclear outage costs and other operating cost reductions including savings from Exelon's Cost Management Initiative.

Depreciation

Depreciation expenses decreased $10 million, or 13%, for the three months ended June 30, 2002 compared to the same period in the prior year due to a $16 million reduction in depreciation expense arising from the extension of the useful lives on certain generation facilities in the third quarter of 2001, partially offset by additional depreciation expense on capital additions placed in service after June 30, 2001 including the acquisition of two generating plants in April 2002.

Taxes Other Than Income

Taxes other than income increased $2 million, or 5%, for the three months ended June 30, 2002 compared to the same period in the prior year primarily due to an increase in property taxes.

Interest Expense

Interest expense decreased $15 million, or 58%, for the three months ended June 30, 2002, compared to the same period in the prior year. The decrease is primarily due to capitalized interest and a lower interest rate on the spent nuclear fuel obligation.

Equity in Earnings of Unconsolidated Affiliates

Equity in earnings of unconsolidated affiliates decreased $4 million, or 31%, for the three months ended June 30, 2002 compared to the same period in the prior year. This decrease was due to a $7 million reduction in Generation's equity earnings in AmerGen, primarily due to a planned plant outage, which began in the first quarter of 2002. This decrease is partially offset by a $3 million increase in Generation's equity earnings in Sithe.

Other, net

Other, net increased $10 million for the three months ended June 30, 2002 compared to the same period in the prior year primarily due to a $10 million increase in investment income from the nuclear decommissioning trust funds.

Income Taxes

The effective income tax rate was unchanged at 37.7% for the three months ended June 30, 2002 and 2001.

Significant Operating Trends - Generation

	Six Months Ended June 30, 2002	2001	Variance	% Change
OPERATING REVENUES	$ 3,020	$3,211	$ (191)	(5.9%)
OPERATING EXPENSES				
Purchased Power	1,323	1,320	3	0.2%
Fuel	433	449	(16)	(3.6%)
Operating and Maintenance	844	809	35	4.3%
Depreciation	128	167	(39)	(23.4%)
Taxes Other Than Income	90	85	5	5.9%
Total Operating Expense	2,818	2,830	(12)	(0.4%)
OPERATING INCOME	202	381	(179)	(47.0%)
OTHER INCOME AND DEDUCTIONS				
Interest Expense	(28)	(59)	31	(52.5%)
Equity in Earnings (Losses) of Unconsolidated Affiliates, net	32	39	(7)	(17.9%)
Other, net	40	18	22	122.2%
Total Other Income and Deductions	44	(2)	46	n.m.
INCOME BEFORE INCOME TAXES AND CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	246	379	(133)	(35.1%)
INCOME TAXES	96	150	(54)	(36.0%)
INCOME BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	150	229	(79)	(34.4%)
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES, NET OF INCOME TAXES	13	12	1	8.3%
NET INCOME	$ 163	$ 241	(78)	(32.4%)

Net Income

Generation's net income decreased by $78 million, or 32%, for the six months ended June 30, 2002 compared to the same period in 2001. Net income was adversely impacted by a lower margin on wholesale energy sales due to depressed market prices for energy, a reduced supply of low-cost nuclear generation, and increased operating and maintenance expense partially offset by an increase in revenue from affiliates and lower depreciation and interest expense.

Operating Revenues, Net of Purchased Power and Fuel

Operating revenues, net of purchased power and fuel were $1,264 million for the six months ended June 30, 2002 compared to $1,442 million for the same period in the prior year. The $178 million, or 12%, decrease was due to lower wholesale market prices for energy, which reduced margins by $184 million, which was partially offset by increased revenues from affiliates of $26 million and lower fuel costs. The amount of low-cost nuclear generation available for sale was reduced due to an increased number of nuclear generating station refueling outages in the six months ended June 30, 2002, compared to the same period in 2001. Additionally, trading activities were initiated in April 2001. Revenue for the six months ended June 30, 2002 includes a net trading portfolio loss of $16 million compared to a net $6 million loss in the six months ended June 30, 2001.

For the six months ended June 30, 2002 and 2001, Generation's sales and the supply of these sales excluding the trading portfolio were as follows:

	Six Months Ended June 30,	
Sales (in GWhs)	2002	2001
Energy Delivery	56,044	57,309
Exelon Energy	2,605	3,006
Market Sales	39,913	36,007
Total Sales	98,562	96,322

	Six Months Ended June 30,	
Supply of Sales (in GWhs)	2002	2001
Nuclear Generation	55,886	58,410
Purchases - non-trading portfolio	36,314	31,954
Fossil and Hydro Generation	6,362	5,958
Total Supply	98,562	96,322

Trading volume was 22,805 GWhs and 454 GWhs for the six months ended June 30, 2002 and 2001, respectively.

Generation's average margins on energy sales for the six months ended June 30, 2002 and 2001 are as follows:

	Six Months Ended June 30,	
($/MWh)	2002	2001
Average Realized Revenue		
Energy Delivery	$ 30.73	$ 29.58
Exelon Energy	45.08	39.30
Market Sales	29.44	38.66
Total Sales - excluding the trading portfolio	30.58	33.27
Average Supply Cost - excluding the trading portfolio	17.78	18.75
Average Margin - excluding the trading portfolio	12.80	14.52

Generation's nuclear fleet, including AmerGen, performed at a capacity factor 91.2% for the six months ended June 30, 2002 compared to 96.2% for the same period in 2001. Generation's nuclear fleet's production costs, including AmerGen, for the six months ended June 30, 2002 were $13.38 per MWh compared to $12.34 per MWh for the same period in 2001. The lower capacity factor and increased unit production costs are primarily due to 153 planned outage days in the six months ended June 30, 2002, versus 31 days in the same period in 2001, including AmerGen. Increased unit production costs are partially offset by lower production costs due to headcount reductions and cost savings initiatives. Generation's average purchased power costs for wholesale operations were $36.76 per MWh for the six months ended June 30, 2002, compared to $41.81 per MWh for the same period in 2001. The decrease in purchase power costs was primarily due to depressed wholesale power market prices.

Operating and Maintenance

Operating and maintenance expense increased $35 million, or 4%, for the six months ended June 30, 2002 compared to the same period in 2001. This was due to the additional operating and maintenance expense of $55 million arising from an increased number of nuclear plant refueling outages during the six months ended June 30, 2002 compared to the same period in 2001, as well as additional allocated corporate costs including executive severance. These additional expenses were offset by other operating cost reductions, including $10 million related to headcount reductions, a $10 million reduction in Generation's severance accrual and $4 million in savings from Exelon's Cost Management Initiative. The severance reduction represents a reversal of costs previously charged to operating expense.

Depreciation

Depreciation expenses decreased $39 million, or 23%, for the six months ended June 30, 2002 compared to the same period in 2001 due to a $48 million reduction in depreciation expense arising from the extension of the useful lives on certain generation facilities commencing in the second quarter of 2001, partially offset by additional depreciation expense on capital additions placed in service after June 30, 2001, including the acquisition of two generating plants in April 2002.

Taxes Other Than Income

Taxes other than income increased $5 million, or 6%, for the six months ended June 30, 2002 compared to the same period in 2001 due primarily to the Texas franchisee taxes related to the acquisition of two generating plants from TXU in April 2002 and an increase in property taxes.

Interest Expense

Interest expense decreased $31 million, or 53%, for the six months ended June 30, 2002, compared to the same period in 2001. The decrease is due to capitalized interest and a lower interest rate on the spent nuclear fuel obligation.

Equity in Earnings of Unconsolidated Affiliates

Equity in earnings of unconsolidated affiliates decreased $7 million, or 18%, for the six months ended June 30, 2002 compared to the same period in 2001. This decrease was due to a $12 million reduction in Generation's equity earnings in AmerGen, primarily due to a planned plant outage in 2002. This decrease is partially offset by an increase of $5 million in Generation's equity earnings of Sithe.

Other, net

Other, net increased $22 million, or 122%, for the six months ended June 30, 2002 compared to the same period in 2001, primarily due to a $22 million increase in investment income from the nuclear decommissioning trust funds.

Income Taxes

The effective income tax rate was substantially unchanged at 39.0% for the six months ended June 30, 2002 compared to 39.6% for the same period in 2001.

Cumulative Effect of Changes in Accounting Principles

On January 1, 2002, Generation adopted SFAS No. 141 resulting in a benefit of $13 million (net of income taxes of $9 million).

On January 1, 2001, Generation adopted SFAS No. 133, as amended, resulting in a benefit of $12 million (net of income taxes of $7 million).

LIQUIDITY AND CAPITAL RESOURCES

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financings and borrowings or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on Generation's credit ratings and general business condition, as well as the general business conditions of the industry. Capital resources are used primarily to fund capital requirements, including construction, investments in new and existing ventures, and repayments of maturing debt. Any potential future acquisitions could require external financing or borrowings or capital contributions for Exelon.

Cash Flows from Operating Activities

Cash flows provided by operations were $519 million for the six months ended June 30, 2002, compared to $485 million for the same period in 2001. Generation's cash flows from operating activities primarily result from the sale of electric energy to wholesale customers, including Generation's affiliated companies, as well as settlements arising from Generation's trading activities. Generation's future cash flow from operating activities will depend upon future demand and market prices for energy and the ability to continue to produce and supply power at competitive costs.

Cash Flows from Investing Activities

Cash flows used in investing activities were $1,048 million for the six months ended June 30, 2002, compared to $99 million for the same period in 2001. Capital expenditures were $258 million and the investment in nuclear fuel was $217 million in the six months ended June 30, 2002 compared to capital expenditures of $173 million and investment in nuclear fuel of $128 million in the same period in 2001. In addition to the 2002 capital expenditures, Generation closed the purchase of two natural-gas and oil-fired plants from TXU on April 25, 2002. The $443 million purchase was funded with available cash and borrowings from Exelon. An increased number of nuclear generating station refueling outages occurred during the six months ended June 30, 2002 compared to the same period in 2001. Generation's investing activities were funded from operating activities, borrowings from Exelon and the use of available cash.

In February 2002, Generation entered into an agreement to loan AmerGen up to $75 million at an interest rate of one-month LIBOR plus 2.25%. As of June 30, 2002, AmerGen had borrowed $75 million under this agreement. In July 2002, the loan agreement and the loan were increased to $100 million and the maturity date was extended to July 1, 2003.

Cash Flows from Financing Activities

Cash flows provided by financing activities were $329 million for the six months ended June 30, 2002, compared to cash used of $67 million for the same period in the prior year. In 2002 Generation obtained a $331 million loan from Exelon for the acquisition of two generating plants. The prior year amount represented net distributions of $121 million to Exelon and the issuance of long-term debt of $752 million. Also, in 2001 Generation repaid $696 million it had borrowed from Exelon related to the acquisition of a 49.9% interest in Sithe.

Credit Issues

Generation meets its short-term liquidity requirements primarily through borrowings under bank credit facilities and borrowings from the Exelon intercompany utility money pool. Generation, along with Exelon, ComEd and PECO entered into a $1.5 billion unsecured 364-day revolving credit facility on December 12, 2001 with a group of banks. As of June 30, 2002, no borrowing sublimit had been established for Generation under this credit facility. This credit facility requires Generation to maintain a debt to total capitalization ratio of 65% or less. At June 30, 2002, Generation's debt to total capitalization ratio was 32%.

Generation's access to the capital markets and its financing costs in those markets are dependent on its securities ratings. None of Generation's borrowings are subject to default or prepayment as a result of a downgrading of securities ratings although such a downgrading could increase interest charges under certain bank credit facilities.

From time to time Generation enters into interest rate swap and other derivatives that require the maintenance of investment grade ratings. Failure to maintain investment grade ratings would allow the counterparty to terminate the derivative and settle the transaction on a net present value basis.

Under PUHCA and the Federal Power Act, Generation can only pay dividends from undistributed or current earnings. At June 30, 2002, Generation had undistributed earnings of $686 million.

Contractual Obligations and Commercial Commitments

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments represent commitments triggered by future events. Generation's contractual obligations and commercial commitments as of June 30, 2002 were materially unchanged, other than in the normal course of business, from the amounts set forth in the December 31, 2001 Form10-K except for the following:

- On April 25, 2002 Generation closed the purchase of two generating plants from TXU. The $443 million purchase was funded primarily with borrowings from Exelon.
- On June 26, 2002 Generation agreed to purchase Sithe New England for $543 million plus the assumption of non-recourse debt estimated to be approximately $1.2 billion at the date of purchase. The purchase is estimated to close in November 2002, subject to regulatory approval. See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information about the Sithe New England acquisition.
- Purchase obligations increased by $1.2 billion, primarily due to an increase of $2.0 billion in power only purchases partially offset by a $0.8 billion decrease in net capacity purchase commitments. The increase in power only purchases is primarily due to Generation's agreement to purchase all the energy from Unit No. 1 at Three Mile Island after December 31, 2001 through December 31, 2014. This decrease in net capacity purchase commitments is due primarily to the decision not to exercise the option to purchase 2,684 MWs of capacity from Midwest Generation in 2002 and 2003 as well as the increase in capacity sales under the TXU tolling agreement.

Off Balance Sheet Obligations

Generation owns 49.9% of the outstanding common stock of Sithe and has an option, beginning on December 18, 2002, to purchase the remaining common stock outstanding (Remaining Interest) in Sithe. The purchase option expires on December 18, 2005. In addition, the Sithe stockholders who own in the aggregate the Remaining Interest have the right to require Generation to purchase the Remaining Interest (Put Rights) during the same period in which Generation can exercise its purchase option. At the end of this exercise period, if Generation has not exercised its purchase option and the other Sithe stockholders have not exercised their Put Rights, Generation will have an additional one-time option to purchase shares from the other stockholders in Sithe to bring Generation's ownership in Sithe from the current 49.9% to 50.1% of Sithe's total outstanding common stock.

If Generation exercises its option to acquire the Remaining Interest, or if all the other Sithe stockholders exercise their Put Rights, the purchase price for 70% of the Remaining Interest will be set at fair market value subject to a floor of $430 million and a ceiling of $650 million. The balance of the Remaining Interest will be valued at fair market value subject to a floor of $141 million and a ceiling of $330 million. In either instance, the floor and ceiling will accrue interest from the beginning of the exercise period.

If Generation increases its ownership in Sithe to 50.1% or more, Sithe will become a consolidated subsidiary and Exelon's financial results will include Sithe's financial results from the date of purchase. At June 30, 2002, Sithe had total assets of $4.1 billion and total debt of $2.1 billion, including $1.6 billion of non-recourse project debt of which $1.0 billion is associated with Sithe New England, $0.4 billion of subordinated debt, $49 million of short-term debt, $33 million of capital leases, and excluding $411 million of non-recourse project debt associated with Sithe's equity investments. For the six months ended June 30, 2002, Sithe had revenues of $0.6 billion. As of June 30, 2002, Generation had a $725 million equity investment in Sithe. On June 26, 2002, Generation agreed to purchase Sithe New England for $543 million plus the assumption of approximately $1.2 billion of non-recourse project debt, which is expected to be outstanding at the time of the closing of the purchase. Generation expects to close the purchase of Sithe New England in November 2002, subject to regulatory approval.

Additionally, the debt on the books of Exelon's unconsolidated equity investments and joint ventures is not reflected on Exelon's Consolidated Balance Sheets. Total investee debt, at June 30, 2002 including the debt of Sithe described in the preceding paragraph, is currently estimated to be $2.3 billion ($1.2 billion based on Exelon's ownership interest of the investments).

Generation and British Energy, Generation's joint venture partner in AmerGen, have each agreed to provide up to $100 million to AmerGen at any time for operating expenses.

Other Factors

Generation is a counterparty to Dynegy in various energy transactions. In early July 2002, the credit ratings of Dynegy were downgraded by two credit rating agencies to below investment grade. As of July 29, 2002, Generation had a net receivable from Dynegy of less than $5 million, and consistent with the terms of the existing credit arrangement, has requested collateral in support of this receivable. Generation also has credit risk associated with Dynegy through Generation's equity investment in Sithe. Sithe is a 60% owner of the Independence generating station, a 1,040 MW gas-fired qualified facility that has an energy only long-term tolling arrangement with Dynegy, with a related financial swap arrangement. As of June 30, 2002, Sithe had recognized an asset on its balance sheet related to the fair value of the financial swap agreement with Dynegy that is marked-to-market under the terms of SFAS No. 133. If Dynegy is unable to fulfill the terms of this agreement, Sithe would be required to write-off the fair value asset, which Generation estimates would result in an approximate $15 million reduction in its equity earnings from Sithe, based on Generation's current 49.9% investment ownership in Sithe. Additionally, the future economic value of Sithe's investment in the Independence Station and AmerGen's purchased power arrangement with Illinois Power, a subsidiary of Dynegy, could be impacted by events related to Dynergy's financial condition.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Commodity Price Risk
Generation

Generation's energy contracts are accounted for under SFAS No. 133. Most non-trading contracts qualify for a normal purchases and normal sales exception. Those that do not are recorded as assets or liabilities on the balance sheet at fair value. Changes in the fair value of qualifying cash-flow hedge contracts are recorded in accumulated other comprehensive income, and gains and losses are recognized in earnings when the underlying transaction matures. Mark-to-market gains and losses on other derivative contracts that do not meet hedge criteria under SFAS No. 133 and the ineffective portion of hedge contracts are recognized in earnings on a current basis. Amounts recognized in earnings related to energy contracts for the three months ended June 30, 2002 and 2001 include $17 million of realized gains from cash-flow hedge contract settlements and $5 million in non-cash mark-to-market losses on other derivative contracts, and for the six months ended June 30, 2002 include $54 million of realized gains from cash-flow hedge contract settlements and $2 million in non-cash mark-to market losses on other derivative contracts.

Outlined below is a summary of the changes in fair value for those contracts included as assets and liabilities in Exelon and Generation's Consolidated Balance Sheet for the three months and six months ended June 30, 2002:

	Three Months Ended June 30, 2002	
(in millions)	Non-trading	Trading
Fair value of contracts outstanding as of April 1, 2002	$ (38)	$ 10
Change in fair value during the three months ended June 30, 2002:		
Contracts settled during period	(20)	7
Mark-to-market gain/(loss) on contracts settled during the period	10	(7)
Mark to market gain/(loss) on other contracts	29	(9)
Changes in fair value attributable to changes in valuation techniques and assumptions	--	--
Total change in fair value	19	(9)
Fair value of contracts outstanding at June 30, 2002	$ (19)	$ 1

The total change in fair value during the three months ended June 30, 2002 is reflected in the 2002 financial statements as follows:

	Non-trading	Trading
Mark-to-market gain/(loss) on trading activities and non-qualifying hedge contracts or hedge ineffectiveness reflected in earnings	$ 4	$ (9)
Mark-to-market gain/(loss) on cash-flow hedge contracts reflected in Other Comprehensive Income	15	--
Total change in fair value	$ 19	$ (9)

(in millions)	Six Months Ended June 30, 2002 Non-trading	Trading
Fair value of contracts outstanding as of January 1, 2002	$ 78	$ 14
Change in fair value during the six months ended June 30, 2002:		
Contracts settled during period	(64)	3
Mark-to-market gain/(loss) on contracts settled during the period	21	(8)
Mark to market gain/(loss) on other contracts	(54)	(8)
Changes in fair value attributable to changes in valuation techniques and assumptions	--	--
Total change in fair value	(97)	(13)
Fair value of contracts outstanding at June 30, 2002	$ (19)	$ 1

The total change in fair value during the six months ended June 30, 2002 is reflected in the 2002 financial statements as follows:

	Non-trading	Trading
Mark-to-market gain/(loss) on trading activities and non-qualifying hedge contracts or hedge ineffectiveness reflected in earnings	$ 10	$ (13)
Mark-to-market gain/(loss) on cash-flow hedge contracts reflected in Other Comprehensive Income	(107)	--
Total change in fair value	$ (97)	$ (13)

The majority of Generation's contracts are non-exchange traded contracts valued using prices provided by external sources, which primarily represent price quotations available through brokers or over-the-counter, on-line exchanges. Prices reflect the average of the bid-ask midpoint prices obtained from all sources that Generation believes provide the most liquid market for the commodity. The terms for which such price information is available varies by commodity, by region and by product. The remainder of the assets represent contracts for which external valuations are not available, primarily option contracts. These contracts are valued using the Black model, an industry standard option valuation model, and other valuation techniques and are discounted using a risk-free interest rate. The fair values in each category reflect the level of forward prices and volatility factors as of June 30, 2002 and may change as a result of future changes in these factors.

Mark-to market gains and losses on qualifying cash-flow hedge contracts are recorded in accumulated other comprehensive income, and will be reclassified into earnings when the contract settles. Mark-to-market gains and losses on derivative contracts that do not meet hedge criteria under SFAS No. 133 and the ineffective portion of hedge contracts have been recognized in earnings on a current basis. The maturities, or expected settlement dates, of the qualifying cash flow hedge contracts recorded in accumulated other comprehensive income, and the other non-trading and trading derivative contracts and sources of fair value as of June 30, 2002 are as follows:

	Maturities within			
(in millions)	1 Year	2-3 Years	4-5 Years	Total Fair Value
Non-trading, qualifying cash flow hedge contracts (1):				
Prices provided by other external sources	$ --	$ (24)	$ (6)	$ (30)
Total	$ --	$ (24)	$ (6)	$ (30)
Non-trading, other derivative contracts (2):				
Actively quoted prices	$ 4	$ --	$ --	$ 4
Prices provided by other external sources	22	11	5	38
Prices based on model or other valuation methods	(8)	(6)	(17)	(31)
Total	$ 18	$ 5	$ (12)	$ 11
Trading, other derivative contracts (3):				
Actively quoted prices	$ 1	$ --	$ --	$ 1
Prices provided by other external sources	(3)	(3)	--	(6)
Prices based on model or other valuation methods	4	2	--	6
Total	$ 2	$ (1)	$ --	$ 1

(1) Mark-to-market gains and losses on contracts that qualify as cash-flow hedges are recorded in other comprehensive income.
(2) Mark-to-market gains and losses on other non-trading derivative contracts that do not qualify as cash-flow hedges are recorded in earnings.
(3) Mark-to-market gains and losses on trading contracts are recorded in earnings.

Credit Risk
Exelon and Generation

Generation is a counterparty to Dynegy in various energy transactions. In early July 2002, the credit ratings of Dynegy were downgraded by two credit rating agencies to below investment grade. As of July 29, 2002, Generation had a net receivable from Dynegy of less than $5 million, and consistent with the terms of the existing credit arrangement, has requested collateral in support of this receivable. Generation also has credit risk associated with Dynegy through Generation's equity investment in Sithe. Sithe is a 60% owner of the Independence generating station, a 1,040 MW gas-fired qualified facility that has an energy only long-term tolling arrangement with Dynegy, with a related financial swap arrangement. As of June 30, 2002, Sithe had recognized an asset on its balance sheet related to the fair value of the financial swap agreement with Dynegy that is marked-to-market under the terms of SFAS No. 133. If Dynegy is unable to fulfill the terms of this agreement, Sithe would be required to write-off the fair value asset, which Generation estimates would result in an approximate $15 million reduction in its equity earnings from Sithe, based on Generation's current 49.9% investment ownership in Sithe. Additionally, the future economic value of Sithe's investment in the Independence Station and AmerGen's purchased power arrangement with Illinois Power, a subsidiary of Dynegy, could be impacted by events related to Dynergy's financial condition.

PART II - OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

As previously reported in Exelon's March 2002 Form 10-Q, on May 8, 2002, a class action lawsuit was filed against Exelon on behalf of purchasers of Exelon securities between April 24, 2001 and September 27, 2001 (Class Period). The lawsuit was filed in the United States District Court for the Northern District of Illinois, Eastern Division. The complaint alleges that Exelon violated Federal securities laws by issuing a series of materially false and misleading statements relating to its 2001 earnings expectations during the Class Period. Corbin A. McNeill, Jr., John Rowe and Ruth Ann Gillis were also named as defendants. Between May 8 and June 14, 2002, an additional five nearly identical class actions lawsuits were filed. On May 30 and July 2, 2002, the Court consolidated the cases into one lawsuit. Exelon believes that the lawsuit is without merit and will vigorously contest this matter.

As previously reported in the 2001 Form 10-K and the March 2002 Form 10-Q, several developers of non-utility generating facilities filed litigation against various Illinois officials claiming that the enforcement of an Illinois law amendment, which removed the entitlement of those facilities to receive state-subsidized payments for electricity sold to ComEd after March 15, 1996, violated their rights under the Federal and state constitutions. Subsequently, the developers filed complaints alleging that ComEd breached the contracts in question and requested damages reflecting the state-subsidized rate to which the developers claim they were entitled under their contracts. In July 2002, certain of the plaintiffs produced an expert report claiming approximately $175 million in damages, a quantification ComEd vigorously disputes. Virtually all parties have filed motions for summary judgment. ComEd is contesting each case and has filed its motion for summary judgment arguing that, as a matter of law, it did not breach any of the contracts.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Information regarding the submission of matters to a vote of security holders is presented in the Form 10-Q for the Quarterly period ended March 31, 2002.

ITEM 5. OTHER INFORMATION

ComEd

On May 28, 2002, ComEd filed a declaration with the FERC to join PJM. ComEd committed to place its transmission system under the control of an independent transmission company that would operate within PJM West, which would be managed by National Grid USA and would also include the transmission systems of American Electric Power East and Illinois Power.

On July 19, 2002, ComEd filed a request with the ICC to revise the POLR obligation in Illinois. ComEd is seeking permission from the ICC to limit the availability by June 2006 of Rate 6L for 370 of ComEd's largest energy customers with demands of at least three MWs, totaling approximately 2,500 MWs. Rate 6L is a bundled fixed rate offered to large customers including heavy industrial plants, large office buildings, government facilities and a variety of other businesses. The ICC has 120 days to act on the filing or it will be deemed approved.

On August 1, 2002, ComEd set a new record for highest peak load experienced to date of 21,852 MWs.

PECO

As previously disclosed in the 2001 Form 10-K, in February 2002, New Power notified PECO of its intent to withdraw from providing Competitive Default Service ("CDS") to approximately 180,000 residential customers. As a result of that withdrawal, those CDS customers were returned to PECO in the second quarter of 2002. Pursuant to a tariff filing approved by the Pennsylvania Public Utility Commission, PECO will serve those returned customers at the discount energy rates on generation provided for under the original New Power CDS Agreement for the remaining term of that contract. Subsequently, in the second quarter of 2002, New Power also advised PECO it planned to withdraw from serving all of its customers in Pennsylvania, including approximately 15,000 non-CDS PECO customers, and to return those customers to PECO in September 2002.

On July 29, 2002, PECO set a new record for highest peak load experienced to date of 8,193 MWs.

Generation

On April 25, 2002, Generation completed the purchase of two TXU Energy power plants located in Dallas and Fort Worth areas for 443 million. The agreement was first announced in December 2001. The purchase includes the 893 MW Mountain Creek Steam Electric Station in Dallas and the 1,441 MW Handley Steam Electric Station in Fort Worth. The purchase was funded with available cash and commercial paper.

On June 21, 2002, Generation signed an agreement with Peoples Calumet, LLC to form Southeast Chicago Energy Project, LLC. Southeast Chicago Energy Project LLC will operate a 350MW simple cycle peaking power generating facility consisting of 8 turbines located in Chicago. As of June 30, 2002 Generation's investment in the Southeast Chicago Project, LLC was $166 million.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits:

99.1 - Certification Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes - Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, by John W. Rowe and Ruth Ann M. Gillis for Exelon Corporation.

99.2 - Certification Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes - Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, by Frank M. Clark for Commonwealth Edison Company.

99.3 - Certification Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes - Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, by Robert E. Berdelle for Commonwealth Edison Company.

99.4 - Certification Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes - Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, by Kenneth G. Lawrence for PECO Energy Company.

99.5 - Certification Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes - Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, by Frank F. Frankowski for PECO Energy Company.

99.6 - Certification Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes - Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, by Oliver D. Kingsley for Exelon Generation Company, LLC.

99.7 - Certification Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes - Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2002, by Ruth Ann M. Gillis for Exelon Generation Company, LLC.

99.8 - Management's Discussion and Analysis of Financial Condition and Results of Operations and Index to Financial Statements of Exelon Generation Company, LLC, filed by Exelon Generation Company, LLC with the Securities Exchange Commission on April 24, 2002 on Registration Statement Form S-4 (File No. 333-85496).

(b) Reports on Form 8-K:

Exelon filed Current Reports on Form 8-K during the three months ended June 30, 2002 regarding the following items:

Date of Earliest Event Reported	Description of Item Reported
April 2, 2002	"ITEM 5. OTHER EVENTS" regarding an interim order in Commonwealth Edison's Delivery Services Rate Case.
April 4, 2002	"ITEM 5. OTHER EVENTS" regarding the announcement that an indirect subsidiary of Exelon filed for protection under Chapter 11 of the Bankruptcy Code.
April 10, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding a presentation by representatives of Power Team, Generation's Power Marketing Organization, to Capital Group Companies. The exhibit includes the slides used during the presentation.
April 19, 2002	"ITEM 5. OTHER EVENTS and REGULATION FD DISCLOSURE" regarding the announcement that Ruth Ann M. Gillis, Senior Vice President and Chief Financial Officer, will become Senior Vice President and President, Exelon Business Services Company.
April 22, 2002	"ITEM 5. OTHER EVENTS" reporting Exelon's first quarter 2002 earnings results. Exelon also announced that Nicholas DeBenedictis was elected to the board of directors of Exelon Corporation. "ITEM 9. REGULATION FD DISCLOSURE" regarding highlights of the Exelon First Quarter Earnings Conference Call.
May 2, 2002	"ITEM 5. OTHER EVENTS" regarding the announcement of the completion of the purchase of two TXU Corp. power plants.
May 14, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding a presentation by Ruth Ann M. Gillis, Senior Vice President and CFO of Exelon Corporation, to investors at the Salomon Smith Barney Power & Merchant Energy 2002 Conference. The exhibits include the slides used and copies of the materials made available to investors attending the conference.

May 17, 2002	"ITEM 5. OTHER EVENTS" regarding Commonwealth Edison's resolution of a FERC reporting issue with Illinois Regulators.
May 22, 2002	"ITEM 5. OTHER EVENTS" regarding Exelon's affirmation of Power Team's delivery-based trading strategy.
May 22, 2002	"ITEM 9. REGULATION FD DISCLOSURE" representatives of Exelon Corporation attended the Edison Electric Institute's International Finance Conference held in New York. The exhibits include the materials made available at the conference.
May 23, 2002	"ITEM 5. OTHER EVENTS" regarding Exelon's response to FERC that Power Team did not engage in any of the strategies put forth in the Enron Corp. (Enron) memos referred to in FERC's data request. A copy of Exelon's response to the FERC data request was included as an exhibit.
June 10, 2002	"ITEM 5. OTHER EVENTS" regarding Exelon's reaffirmation of the company's earnings outlook for 2002 and the announcement that it will host an investor conference.
June 12, 2002	"ITEM 9. REGULATION FD DISCLOSURE" John W. Rowe, President and CEO of Exelon, made a presentation to investors at the Deutsche Bank Electric and Power Conference. The exhibits include the presentation slides and other materials made available at the conference.
June 20, 2002	"ITEM 9. REGULATION FD DISCLOSURE" senior officers of Exelon made presentations at the Exelon Investor Conference in New York City. The exhibits include the presentation slides and other materials made available at the conference.
June 20, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding additional information management provided during Exelon's Investor Conference in New York on June 20, 2002.
June 27, 2002	"ITEM 5. OTHER EVENTS" a note to Exelon's financial community regarding Exelon Generation's agreement to purchase Sithe New England Holdings, LLC.

ComEd filed Current Reports on Form 8-K during the three months ended June 30, 2002 regarding the following items:

Date of Earliest Event Reported	Description of Item Reported

April 2, 2002	"ITEM 5. OTHER EVENTS" regarding an interim order in Commonwealth Edison's Delivery Services Rate Case.
April 22, 2002	"ITEM 5. OTHER EVENTS" reporting Exelon's first quarter 2002 earnings results. Exelon also announced that Nicholas DeBenedictis was elected to the board of directors of Exelon Corporation. "ITEM 9. REGULATION FD DISCLOSURE" regarding highlights of the Exelon First Quarter Earnings Conference Call.
May 14, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding a presentation by Ruth Ann M. Gillis, Senior Vice President and CFO of Exelon Corporation, to investors at the Salomon Smith Barney Power & Merchant Energy 2002 Conference. The exhibits include the slides used and copies of the materials made available to investors attending the conference.
May 17, 2002	"ITEM 5. OTHER EVENTS" regarding Commonwealth Edison's resolution of a FERC reporting issue with Illinois Regulators.
May 22, 2002	"ITEM 9. REGULATION FD DISCLOSURE" representatives of Exelon Corporation attended the Edison Electric Institute's International Finance Conference held in New York. The exhibits include the materials made available at the conference.
June 12, 2002	"ITEM 9. REGULATION FD DISCLOSURE" John W. Rowe, President and CEO of Exelon, made a presentation to investors at the Deutsche Bank Electric and Power Conference. The exhibits include the presentation slides and other materials made available at the conference.
June 20, 2002	"ITEM 9. REGULATION FD DISCLOSURE" senior officers of Exelon made presentations at the Exelon Investor Conference in New York City. The exhibits include the presentation slides and other materials made available at the conference.
June 20, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding additional information management provided during Exelon's Investor Conference in New York on June 20, 2002.

PECO filed Current Reports on Form 8-K during the three months ended June 30, 2002 regarding the following items:

Date of Earliest Event Reported	Description of Item Reported

April 22, 2002	"ITEM 5. OTHER EVENTS" reporting Exelon's first quarter 2002 earnings results. Exelon also announced that Nicholas DeBenedictis was elected to the board of directors of Exelon Corporation. "ITEM 9. REGULATION FD DISCLOSURE" regarding highlights of the Exelon First Quarter Earnings Conference Call.
May 14, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding a presentation by Ruth Ann M. Gillis, Senior Vice President and CFO of Exelon Corporation, to investors at the Salomon Smith Barney Power & Merchant Energy 2002 Conference. The exhibits include the slides used and copies of the materials made available to investors attending the conference.
May 22, 2002	"ITEM 9. REGULATION FD DISCLOSURE" representatives of Exelon Corporation attended the Edison Electric Institute's International Finance Conference held in New York. The exhibits include the materials made available at the conference.
June 12, 2002	"ITEM 9. REGULATION FD DISCLOSURE" John W. Rowe, President and CEO of Exelon, made a presentation to investors at the Deutsche Bank Electric and Power Conference. The exhibits include the presentation slides and other materials made available at the conference.
June 20, 2002	"ITEM 9. REGULATION FD DISCLOSURE" senior officers of Exelon made presentations at the Exelon Investor Conference in New York City. The exhibits include the presentation slides and other materials made available at the conference.
June 20, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding additional information management provided during Exelon's Investor Conference in New York on June 20, 2002.

Generation filed Current Reports on Form 8-K during the three months ended June 30, 2002 regarding the following items:

Date of Earliest Event Reported	Description of Item Reported
May 2, 2002	"ITEM 5. OTHER EVENTS" regarding the announcement of the completion of the purchase of two TXU Corp. power plants.
May 14, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding a presentation by Ruth Ann M. Gillis, Senior Vice President and CFO of Exelon Corporation, to investors at the Salomon Smith Barney Power & Merchant Energy 2002

	Conference. The exhibits include the slides used and copies of the materials made available to investors attending the conference.
May 22, 2002	"ITEM 5. OTHER EVENTS" regarding Exelon's affirmation of Power Team's delivery-based trading strategy.
May 22, 2002	"ITEM 9. REGULATION FD DISCLOSURE" representatives of Exelon Corporation attended the Edison Electric Institute's International Finance Conference held in New York. The exhibits include the materials made available at the conference.
May 23, 2002	"ITEM 5. OTHER EVENTS" regarding Exelon's response to FERC that Power Team did not engage in any of the strategies put forth in the Enron memos referred to in FERC's data request. A copy of Exelon's response to the FERC data request was included as an exhibit.
June 12, 2002	"ITEM 9. REGULATION FD DISCLOSURE" John W. Rowe, President and CEO of Exelon, made a presentation to investors at the Deutsche Bank Electric and Power Conference. The exhibits include the presentation slides and other materials made available at the conference.
June 20, 2002	"ITEM 9. REGULATION FD DISCLOSURE" senior officers of Exelon made presentations at the Exelon Investor Conference in New York City. The exhibits include the presentation slides and other materials made available at the conference.
June 20, 2002	"ITEM 9. REGULATION FD DISCLOSURE" regarding additional information management provided during Exelon's Investor Conference in New York on June 20, 2002.
June 27, 2002	"ITEM 5. OTHER EVENTS" a note to Exelon's financial community regarding Exelon Generation's agreement to purchase Sithe New England Holdings, LLC.

SIGNATURES

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

EXELON CORPORATION

/s/ John W. Rowe

JOHN W. ROWE
President and CEO

/s/ Ruth Ann M. Gillis

RUTH ANN M. GILLIS
Senior Vice President and Chief Financial Officer

/s/ Matthew F. Hilzinger

MATTHEW F. HILZINGER
Vice President and Corporate Controller
(Principal Accounting Officer)

August 6, 2002

SIGNATURES

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

COMMONWEALTH EDISON COMPANY

/s/ Pamela B. Strobel

PAMELA B. STROBEL
Chairman and CEO
Exelon Energy Delivery

/s/ Frank M. Clark

FRANK M. CLARK
President

/s/ Robert E. Berdelle

ROBERT E. BERDELLE
Vice President and Chief Financial Officer
(Principal Accounting Officer)

August 6, 2002

SIGNATURES

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

PECO ENERGY COMPANY

/s/ Pamela B. Strobel

PAMELA B. STROBEL
Chairman and CEO
Exelon Energy Delivery

/s/ Ken G. Lawrence

KEN G. LAWRENCE
President

/s/ Frank F. Frankowski

FRANK F. FRANKOWSKI
Vice President and Chief Financial Officer
(Principal Accounting Officer)

August 6, 2002

SIGNATURES

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

EXELON GENERATION COMPANY, LLC

/s/ Oliver D. Kingsley Jr.

OLIVER D. KINGSLEY JR.
CEO and President

/s/ Ruth Ann M. Gillis

RUTH ANN M. GILLIS
Senior Vice President and Chief Financial Officer
Exelon Corporation
(Principal Financial Officer)

August 6, 2002

Exhibit 99.1

Certificate Pursuant to Section 1350
of Chapter 63 of Title 18 United States Code

The undersigned officers hereby certify, as to the Quarterly Report on Form 10-Q of Exelon Corporation for the quarterly period ended June 30, 2002, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation and its subsidiaries.

Date: August 6, 2002

/s/ John W. Rowe

John W. Rowe
Chairman and Chief Executive Officer
Exelon Corporation

Date: August 2, 2002

/s/ Ruth Ann M. Gillis

Ruth Ann M. Gillis
Senior Vice President and Chief Financial Officer
Exelon Corporation

Exhibit 99.2

Certificate Pursuant to Section 1350
of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Quarterly Report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2002, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company and its subsidiaries.

Date: August 6, 2002

/s/ Frank M. Clark

Frank M. Clark
President (Chief Executive Officer)
Commonwealth Edison Company

Exhibit 99.3

Certificate Pursuant to Section 1350
of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Quarterly Report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended June 30, 2002, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company and its subsidiaries.

Date: August 2, 2002

/s/ Robert E. Berdelle

Robert E. Berdelle
Vice President, Finance and Chief Financial Officer
Commonwealth Edison Company

Exhibit 99.4

Certificate Pursuant to Section 1350
of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Quarterly Report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2002, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company and its subsidiaries.

Date: August 6, 2002

/s/ Kenneth G. Lawrence

Kenneth G. Lawrence
President (Chief Executive Officer)
PECO Energy Company

Exhibit 99.5

Certificate Pursuant to Section 1350
of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Quarterly Report on Form 10-Q of PECO Energy Company for the quarterly period ended June 30, 2002, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company and its subsidiaries.

Date: July 31, 2002

/s/ Frank F. Frankowski

Frank F. Frankowski
Vice President, Finance and Chief Financial Officer
PECO Energy Company

Exhibit 99.6

Certificate Pursuant to Section 1350
of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Quarterly Report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2002, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC and its subsidiaries.

Date: August 5, 2002

/s/ Oliver D. Kingsley, Jr.

Oliver D. Kingsley, Jr.
CEO and President (Chief Executive Officer)
Exelon Generation Company, LLC

Exhibit 99.7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Quarterly Report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended June 30, 2002, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC and its subsidiaries.

Date: August 2, 2002

/s/ Ruth Ann M. Gillis

Ruth Ann M. Gillis
Chief Financial Officer
Exelon Generation Company, LLC

Exhibit 99.8

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Results of Operations

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Net Income. Our net income increased $264 million, or 102%, for 2001. Income before cumulative effect of changes in accounting principles increased $252 million, or 97%, for 2001.

Earnings Before Interest and Income Taxes. We and our parent Exelon evaluate our performance based on earnings before interest and income taxes (EBIT). In addition to components of operating income as shown on the consolidated statements of income, EBIT includes equity in earnings of unconsolidated affiliates, and other income and expense recorded in other, net, with the exception of investment income.

The October 20, 2000 merger of PECO and Unicom, and the January 1, 2001 corporate restructuring, significantly impacted our results of operations. To provide a more meaningful analysis of results of operations, the EBIT analyses below identifies the portion of the EBIT variance that is attributable to the former ComEd generation business unit results of operations and the portion of the variance that results from normal operations attributable to changes in components of our underlying operations. The merger variance represents the former ComEd generation business unit results for the year ended December 31, 2000 prior to the October 20, 2000 acquisition date as well as the effect of merger-related costs incurred in 2000. The 2000 effects of the merger and restructuring were developed using estimates of various items, including allocation of corporate overheads and intercompany transactions.

			Components of Variance	
	2001	**2000**	**Variance**	**Merger Variance**	**Normal Operations**
			(in millions)		
Operating Revenue	$ 7,048	$ 3,274	$ 3,774	$ 2,772	$ 1,002
Fuel & Purchased Power	4,218	1,846	2,372	1,689	683
Operating & Maintenance and Other	1,586	858	728	978	(250)
Depreciation & Decommissioning	282	123	159	83	76
EBIT	$ 962	$ 447	$ 515	$ 22	$ 493

Our EBIT increased $515 million for 2001 compared to 2000. This increase was primarily attributable to higher margins on increased market and affiliate wholesale energy sales, coupled with reduced operating expenses at the nuclear plants, partially offset by additional depreciation and decommissioning expense. During the first five months of 2001, we benefited from increases in wholesale market prices, particularly in the Pennsylvania-New Jersey-Maryland control area and Mid-America Interconnected Network regions. The increase in wholesale market prices was primarily driven by significant increases in fossil fuel prices. The large concentration of nuclear generation in our portfolio allowed us to capture the higher prices in the wholesale market for sales to non-affiliates with minimal increase in fuel prices. Our revenues for 2001 include charges to affiliates for line losses. Line loss charges were not included in 2000 revenue. We also benefited from higher nuclear plant output due to increased capacity factors during 2001. Energy marketing activities positively impacted 2001 results. Mark-to-market gains were $16 million and $14 million on non-trading and trading energy contracts, respectively, offset by realized trading losses of $6 million.

Our sales were 201,879 GWhs in 2001 compared to 200,072 GWhs in 2000, approximately 60% of which were to affiliates. Supply sources for 2001 and 2000 were as follows:

	2001	**2000**
Operated nuclear units	54%	54%
Purchases	37%	37%
Fossil and hydro units	3%	3%
Generation investments	6%	6%
Total	100%	100%

Our nuclear fleet, including AmerGen, performed at a weighted average capacity factor of 94.4% for 2001 compared to 93.8% in 2000. Our nuclear fleet's production costs, including AmerGen, were $12.79 per MWh for 2001, compared to $14.65 per MWh for 2000. Our purchased power costs were $42.26 MWh for 2001, compared to $38.05 per MWh for 2000. The increase resulted in purchase power costs from the increase in fuel prices in the first quarter of 2001 as well as the increase in volumes sold during peak demand in 2001 compared to 2000.

Operating expenses were favorably affected by reductions in labor costs due to a decline in the number of employees and fewer nuclear outages in 2001 than in 2000, which offset the effect of increases in litigation-related expenses of $30 million. In addition, our EBIT benefited from an increase in equity in earnings of AmerGen and Sithe of $86 million in 2001 compared to the prior-year period reflecting a full year of operations for Sithe and AmerGen's Oyster Creek plant in 2001.

The increase in depreciation and decommissioning expense is primarily due to an increase in decommissioning expense of $140 million resulting from the discontinuance of regulatory accounting practices associated with decommissioning costs for the former ComEd nuclear generating stations that are in active generation, partially offset by a $90 million reduction in depreciation and decommissioning expense attributable to the extension of estimated service lives of our generating plants.

Other Components of Net Income

Interest Expense. Interest expense increased $74 million in 2001, from $41 million, in 2000. This increase was primarily attributable to increased interest charge on the note payable to Exelon of $23 million, interest charges of $26 million due to the issuance of $700 million of 6.95% senior unsecured notes in a 144A offering in June 2001, $23 million of additional interest due to a full year of interest charges on the spent fuel obligation compared to only two months in 2000 for the former ComEd generating stations and $15 million of interest charges from affiliates. These increases were partially offset by capitalized interest of approximately $17 million.

Investment Income. Investment income is recorded in Other, Net on the Consolidated Statements of Income, but is excluded from EBIT. Investment income decreased by $29 million due to net realized losses of $127 million offset by interest and dividend income of $67 million on the nuclear decommissioning trust funds reflecting the discontinuance of regulatory accounting practices associated with nuclear decommissioning costs for the nuclear stations formerly owned by ComEd, primarily offset by increased income of $31 million of money market interest and interest on the loan to Sithe recorded in 2001.

Income Taxes. The effective income tax rate was 39.0% for 2001 as compared to 38.1% for 2000. The increase in the effective income tax rate was primarily attributable to a higher effective state income rate due to operations in Illinois subsequent to the merger and a reduction in the investment tax credit. Income taxes increased by $167 million in 2001 as compared to 2000, $160 million of which is due to higher pretax income and $7 million due to a higher effective income tax rate.

Cumulative Effect of Changes in Accounting Principles

On January 1, 2001, we adopted Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities" (SFAS No. 133), as amended, resulting in a benefit of $12 million, net of income taxes.

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Net Income. Our net income increased $56 million, or 27%, in 2000.

Earnings Before Interest and Income Taxes. To provide a more meaningful analysis of our results of operations, the EBIT analysis below identifies the portion of the EBIT variance that is attributable to the former ComEd generation business unit results of operations and the portion of the variance that results from normal operations attributable to changes in components of our underlying operations. The merger variance represents the former ComEd generation business unit results for the period after October 20, 2000 as well as the effect of merger-related costs incurred in 2000. The 2000 and 1999 results also reflect the corporate restructuring as if it had occurred on January 1, 1999. The 2000 effects of the merger and restructuring were developed using estimates of various items, including allocation of corporate overheads and intercompany transactions.

				Components of Variance	
	2000	1999	Variance	Merger Variance	Normal Operations
			(in millions)		
Operating Revenue	$ 3,274	$ 2,425	$ 849	$ 561	$ 288
Fuel & Purchased Power	1,846	1,205	641	279	362
Operating Expense and Other	858	765	93	180	(87)
Depreciation & Decommissioning	123	125	(2)	31	(33)
EBIT	$ 447	$ 330	$ 117	$ 71	$ 46

Our EBIT increased $117 million for 2000 compared to 1999. The merger accounted for $71 million of the variance. The remaining $46 million increase resulted primarily from higher margins on market and affiliate wholesale energy sales, a charge against earnings of $15 million related to the abandonment of two information systems implementations in 1999 and a $15 million write-off in 1999 of the investment in a cogeneration facility in connection with the settlement of litigation. Our EBIT benefited from an increase in equity in earnings of AmerGen of $4 million in 2000 compared to the prior-year period. Effective with the acquisition of Clinton Nuclear Power Station by AmerGen, our agreement to manage Clinton was terminated, resulting in lower revenues of $99 million and lower operating and maintenance expense of $70 million.

Our nuclear fleet, including AmerGen, performed at a weighted average capacity factor of 93.8% for 2000. Our nuclear fleet production costs for 2000, including AmerGen, were $14.65 per MWh. Our purchased power costs for 2000 were $38.05 per MWh.

Other Components of Net Income

Interest Expense. Interest expense increased $29 million, or 242%, to $41 million in 2000. The increase was primarily attributable to interest related to the spent fuel obligation of the former ComEd nuclear plants, which was assumed in connection with the merger, and interest expense related to the $696 million note payable to Exelon used to finance our investment in Sithe.

Income Taxes. The effective tax rate was 38.1% in 2000 as compared to 38.0% in 1999.

Liquidity and Capital Resources

Our capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financings and borrowings or capital contributions from Exelon. Our access to external financing at reasonable terms is dependent on our credit ratings and our general business condition, as well as the general business conditions of the industry. Our business is capital intensive. Capital resources are used primarily to fund our capital requirements, including construction, investments in new and existing ventures, and repayments of maturing debt. Any potential future acquisitions could require external financing or borrowings or capital contributions for Exelon.

Cash Flows from Operating Activities. Cash flows provided by operations for 2001 were $1.3 billion. Our cash flows from operating activities primarily result from the sale of electric energy to wholesale customers, including our affiliated companies. Our future cash flow from operating activities will depend upon future demand and market prices for energy and the ability to continue to produce and supply power at competitive costs.

Cash Flows from Investing Activities. Cash flows used in investing activities for 2001 were $1.1 billion, primarily for capital expenditures of $515 million, investment in nuclear fuel of $336 million and $239 million related to our investment in the nuclear decommissioning funds. We project capital expenditures of approximately $1.1 billion in 2002, approximately 75% of which are for additions to and upgrades of existing facilities, nuclear fuel and increases in capacity at existing plants. Capital expenditures are projected to increase in 2002 as compared to 2001 due to higher nuclear fuel expenditures, growth and an increase in the number of planned refueling outages, during which significant maintenance work is performed. Eleven nuclear refueling outages, including AmerGen, are planned for 2002, compared to six during 2001. Total capital expenditures during nuclear refueling outages are expected to increase in 2002 over 2001 by $24 million. We anticipate that our capital expenditures will be funded by internally generated funds, external borrowings, and borrowings or capital contributions from Exelon. Our proposed capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

In addition to the 2002 capital expenditures of $1.1 billion, we expect to close the purchase of two natural-gas and oil-fired plants from TXU Corp. (TXU) in the second quarter of 2002. The $443 million purchase is expected to be funded with available cash and borrowings from Exelon.

During 2001, we loaned Sithe $150 million, which was repaid by Sithe in December of 2001. During 2001, Sithe paid us $2 million in interest on the loan.

Cash Flows from Financing Activities. Cash flows used in financing activities were $1 million in 2001 primarily attributable to the issuance of $700 million of senior unsecured notes with a maturity of June 2011 The majority of the proceeds of this issuance were used to repay Exelon for amounts borrowed to finance our investment in Sithe. We also issued $121 million of pollution control bonds to refinance an equivalent amount originally issued by PECO.

Credit Issues. We meet short-term liquidity requirements primarily through internally generated cash or borrowings from Exelon. We, along with ComEd, PECO and Exelon, entered into a $1.5 billion unsecured revolving credit facility with a group of banks. We currently cannot borrow under the credit agreement until we deliver audited financial statements to the banks, which is expected to occur in the second quarter of 2002. At December 31, 2001, we had outstanding $700 million of 6.95% senior unsecured debt, $317 million of variable rate pollution control notes and other long-term notes payable of $9 million. For 2001, the average interest rate on these pollution control notes was approximately 2.62% Certain of the credit agreements to which we are party require us to maintain a debt to total capitalization ratio of 65% or less. At December 31, 2001, our debt to total capitalization ratio on that basis was 35%.

Our access to the capital markets and financing costs in those markets is dependent on our securities ratings. None of our borrowings are subject to default or prepayment as a result of a downgrading of securities ratings, although such a downgrading could increase interest charges under the bank credit facility. We enter agreements to purchase energy and capacity, including obligations that are treated as derivatives, which require us to maintain investment grade ratings. Failure to maintain investment grade ratings would allow a counterparty to terminate its contract and settle the transaction on a net present value basis. Exelon has provided guarantees to support certain of our lines of credit, surety bonds, nuclear insurance and energy marketing contracts.

Exelon has obtained an order from the SEC under PUHCA authorizing financing transactions, including the issuance of common stock, preferred securities, long-term debt and short-term debt in an aggregate amount not to exceed $4 billion. The order applies to our issuances as well. As of December 31, 2001, $3.0 billion of financing authority was available under the SEC order. Exelon requested, and the SEC reserved jurisdiction over, an additional $4 billion in financing authorization. Exelon agreed to limit its short-term debt outstanding to $3 billion of the $4 billion total financing authority. Exelon has asked the SEC to eliminate the short-term debt restriction. The SEC order also authorized Exelon to issue guarantees of up to $4.5 billion outstanding at any one time. At December 31, 2001, Exelon had provided $1.4 billion of guarantees. Under PUHCA and the Federal Power Act, we can pay dividends only from retained or current earnings. At December 31, 2001, we had retained earnings of $524 million. Exelon is also limited by order of the SEC under PUHCA to an aggregate investment of $4 billion in exempt wholesale generators (EWGs) and foreign utility companies (FUCOs). Exelon requested, and the SEC reserved jurisdiction over, an additional $1.5 billion investment in EWGs and FUCOs.

Contractual Obligations and Commercial Commitments. Our contractual obligations and commercial commitments as of December 31, 2001 are as follows:

Obligations/Commitments	Total	Payment Due Within 1 Year	2-3 Years	4-5 Years	Due After 5 Years
			($ in millions)		
Long-Term Debt(a)	$ 1,025	$ 4	$ 5	$ —	$ 1,016
Operating Leases(b)	682	28	63	64	527
Purchase Power Obligations(c)	12,192	1,695	3,173	1,346	5,978
Acquisition of TXU Generating Stations(d)	443	443	—	—	—
Spent fuel obligation(e)	843	—	—	—	843

(a) Comprised primarily of senior unsecured debt and pollution control notes. In connection with the variable rate debt, we maintain direct pay letters of credit in order to provide liquidity in the event that it is not possible to remarket all of the debt as required following specific events, including changes in the basis of determining the interest rate of debt. Letters of credit as of December 31, 2001 amounted to $317 million, of which $121 million expire in 2002 and the remaining $196 million expire in 2003 to 2004. Total includes the current portion of long-term debt.

(b) Company leases equipment and certain office facilities.

(c) Commitments relating to the purchase of energy, capacity and transmission rights. Included in amounts are $3,485 million of power purchases from our affiliate AmerGen.

(d) Commitment to purchase generating stations in spring of 2002.

(e) One-time fee of $277 million with interest to date payable to the DOE for Spent Nuclear Fuel.

We have an obligation to decommission our nuclear power plants. Our current estimate of decommissioning costs for our owned nuclear plants is $7.2 billion in current-year (2002) dollars.

Nuclear decommissioning activity occurs primarily after a plant's retirement and is currently estimated to begin in 2029, except for the retired Zion station, which is currently estimated to begin decommissioning in 2013. Decommissioning costs are recoverable by ComEd and PECO through regulated rates and are remitted to us for deposit in the decommissioning trust funds. In 2001, ComEd and PECO collected from customers and remitted to us approximately $102 million in decommissioning costs. At December 31, 2001, the decommissioning liability, which is recorded over the life of the plant, recorded in Property, Plant and Equipment, Net as well as Deferred Credits and Other Liabilities on our balance sheet was $2.7 billion and $1.3 billion, respectively. In order to fund future decommissioning costs, we held $3.2 billion of investments in nuclear decommissioning trust funds, which are included as Deferred Debits and Other Assets on our balance sheet and which include net unrealized and realized gains. Due to the performance of the United States debt and equity markets in 2001, the value of assets held in trusts to satisfy the obligations of the nuclear generating stations eventual decommissioning has decreased. Contributions to the nuclear decommissioning trust funds of $112 million offset net losses of $109 million, resulting in a 2% increase in the decommissioning trust funds balance at December 31, 2001 compared to December 31, 2000. We believe that the amounts being remitted to us by ComEd and PECO and the earnings on nuclear decommissioning trust funds will be sufficient to fully fund our decommissioning obligations.

Off Balance Sheet Obligations. Beginning December 18, 2002, we will have the right to purchase all (but not less than all) of the remaining outstanding shares of the Sithe common stock. The option expires on December 18, 2005. In addition, each of Sithe's other stockholder groups will have the right to require us to purchase all (but not less than all) of its shares during the same period in which we can exercise our option. At the end of that period, if no stockholder has exercised its option, we will have a one-time option to purchase shares from the other stockholders to bring our holdings to 50.1% of the total outstanding shares. If we exercise our option or if all the stockholder groups exercise their put rights, the purchase price for 70% of the remaining 50.1% of the Sithe stock will be set at a fair market value plus a 10% premium in the case of a call or 10% discount in the case of a put, subject to a floor of $430 million and a ceiling of $650 million, and the remaining portion will be valued at fair market value subject to floor price of $141 million and a ceiling price of $330 million, plus, in each case, interest accrued from the beginning of the exercise period.

If we increase our ownership in Sithe to 50.1% or more, Sithe will become a consolidated subsidiary and our financial results will include Sithe's financial results from the date of purchase. At December 31, 2001, Sithe had total assets of $4.2 billion and long-term debt of $2.3 billion, including $2.1 billion of non-recourse project debt and excluding $107 million of non-recourse project debt associated with Sithe's equity investments. For the year ended December 31, 2001 Sithe had revenues of $1 billion. As of December 31, 2001, we had a $725 million equity investment in Sithe.

Additionally, the debt on the books of our unconsolidated equity investments and joint ventures is not reflected on our Consolidated Balance Sheets. Total investee debt, including the debt of Sithe described in the preceding paragraph, is currently estimated to be $2.4 billion ($1.2 billion based on Exelon Generation's ownership interest of the investments).

We and British Energy, our joint venture partner in AmerGen, have each agreed to provide up to $100 million to AmerGen at any time for operating expenses. We have committed to provide AmerGen with capital contributions equivalent to 50% of the purchase price of any acquisitions AmerGen makes in 2002.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risks associated with commodity price, credit, interest rates and equity prices. The inherent risk in market sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, counterparty credit, interest rates and equity security prices.

Exelon's corporate Risk Management Committee (RMC) sets forth risk management philosophy and objectives through a corporate policy, and establishes procedures for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of derivative activity and risk exposures. The RMC is chaired by Exelon's chief risk officer and includes the chief financial officer, general counsel, treasurer, vice president of corporate planning and officers from each of the Exelon business units. The RMC reports to the Exelon Board of Directors on the scope of our derivative and risk management activities.

Commodity Price Risk. Commodity price risk is associated with market price movements resulting from excess or insufficient generation, changes in fuel costs, market liquidity and locational price commodity differences. Trading activities and non-trading marketing activities include the purchase and sale of electric capacity and energy and fossil fuels, including oil, gas and coal. The availability and prices of energy and energy-related commodities are subject to fluctuations due to factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies and other events.

Marketing (non-trading) activities. To the extent that our generation supply (either owned or contracted) is in excess of our obligations to customers, including ComEd's and PECO's retail load, the available electricity is sold in the wholesale markets. To reduce price risk caused by market fluctuations, we enter into derivative contracts, including forwards, futures, swaps, and options with approved counterparties, to hedge our anticipated exposures. Market price risk exposure is the risk of a change in the value of unhedged positions. We expect to maintain a minimum 80% hedge ratio in 2002 for our energy marketing portfolio. This hedge ratio represents the percentage of our forecasted aggregate annual generation supply that is committed to firm sales, including sales to our affiliated entities. The hedge ratio is not fixed and will vary from time to time depending upon market conditions, demand and volatility. Absent any opportunistic efforts to mitigate market price exposure, the estimated market price exposure for the non-trading portfolio associated with a 10% reduction in the average around-the-clock market price of electricity is an approximate $100 million decrease in net income. This sensitivity assumes an 80% hedge ratio and that price changes occur evenly throughout the year and across all markets. The sensitivity also assumes a static portfolio. We expect to actively manage our portfolio to mitigate the market price exposure. Actual results could differ depending on the specific timing of, and markets affected by, the price changes, as well as future changes in our portfolio.

Trading activities. We began to use financial contracts for trading purposes in the second quarter of 2001. The trading activities were entered into as a complement to our energy marketing portfolio and represent a very limited portion of our overall energy marketing activities. For example, the limit on open positions in electricity for any forward month represents less than 5% of the owned and contracted supply of electricity. The trading portfolio is planned to grow modestly in 2002, subject to stringent risk management limits and policies, including volume, stop-loss and value-at-risk limits to manage exposure to market risk. A value-at-risk (VAR) model is used to assess the market risk associated with financial derivative instruments entered into for trading purposes. VAR represents the potential gains or losses for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. The measured VAR as of December 31, 2001, using a Monte Carlo model with a 95% confidence level and assuming a one-day time horizon was approximately $800,000. The measured VAR represents an estimate of the potential change in value of our portfolio of trading related financial derivative instruments. These estimates, however, are not necessarily indicative of actual results, which may differ due to the fact that actual market rate fluctuations may differ from forecasted fluctuations and due to the fact that the portfolio may change over the holding period.

Our energy contracts are accounted for under SFAS No. 133. Most non-trading contracts qualify for a normal purchases and normal sales exception under that accounting pronouncement and therefore are not recorded on the balance sheet and marked to market. Contracts that do not qualify for the

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exception are recorded as assets or liabilities on the balance sheet at fair value. Changes in the fair value of qualifying hedge contracts are recorded in Other Comprehensive Income, and gains and losses are recognized in earnings when the underlying transaction occurs. Changes in the fair value of derivative contracts that do not meet hedge criteria under SFAS No. 133 or the ineffective portion of hedge contracts is recognized in earnings on a current basis. Outlined below is a summary of the changes in fair value for those contracts included as assets and liabilities in our balance sheet for the year ended December 31, 2001:

	Non-trading	Trading
	(in millions)	
Fair value of contracts outstanding as of January 1, 2001 (Reflects the adoption of SFAS No. 133)	$ (7)	$ —
Change in fair value during 2001:		
Contracts settled during year	87	7
Mark-to-market unrealized gain (loss)	(2)	7
Total change in Fair Value	85	14
Fair value of contracts outstanding at December 31, 2001	$ 78	$ 14

The total change in fair value during 2001 is reflected in the 2001 consolidated financial statements as follows:

	Non-trading	Trading
Mark-to-market gain on non-qualifying hedge contracts or hedge ineffectiveness reflected in earnings	$ 16	$ 14
Mark-to market hedge contracts reflected in Other Comprehensive Income	69	—
Total change in fair value	$ 85	$ 14

The majority of our contracts are non-exchange traded contracts valued using prices provided by external sources, which primarily represent price quotations available through brokers or over-the-counter, on-line exchanges. Prices reflect the average of the bid-ask midpoint prices obtained from all sources that we believe provide the most liquid market for the commodity. The terms for which such price information is available varies by commodity, by region and by product. The remainder of the assets represents contracts for which external valuations are not available, primarily option contracts. These contracts are valued using the Black model, an industry standard option valuation model and other valuation techniques. The fair values in each category reflect the level of forward prices and volatility factors as of December 31, 2001 and may change as a result of future

changes in these factors. The maturities of the net energy trading and non-trading assets and sources of fair value as of December 31, 2001 are as follows:

	Less than One Year	One - Three Years	Three - Five Years	Total Fair Value
	(in millions)			
Non-trading:				
Actively quoted prices	$ —	$ —	$ —	$ —
Prices provided by other external sources	36	50	—	86
Prices based on model or other valuation methods	(4)	2	(6)	(8)
Total	$ 32	$ 52	$ (6)	$ 78
Trading:				
Actively quoted prices	$ —	$ —	$ —	$ —
Prices provided by other external sources	10	4	—	14
Prices based on model or other valuation methods	—	—	—	—
Total	$ 10	$ 4	$ —	$ 14

Management uses its best estimates to determine the fair value of commodity and derivative contracts it holds and sells. These estimates consider various factors, including closing exchange and over-the-counter price quotations, time value, volatility factors, and credit exposure. However, it is possible that future market prices could vary from those used in recording assets and liabilities from energy marketing and trading activities, and such variations could be material.

Credit Risk. We have credit risk associated with counterparty performance, which includes, but is not limited to, the risk of financial default or slow payment. Counterparty credit risk is managed through established policies, including establishing counterparty credit limits, and in some cases requiring deposits or letters of credit to be posted by certain counterparties. Our counterparty credit limits are based on a scoring model that considers a variety of factors, including leverage, liquidity, profitability, credit ratings and risk management capabilities. We have entered into master netting agreements with the majority of our large counterparties, which reduce exposure to risk by providing for the offset of amounts payable to the counterparty against the counterparty receivables.

We participate in the five established, real-time energy markets, which are administered by independent system operators (ISOs): Pennsylvania, New Jersey, Maryland, LLC (PJM), which is in the Mid-Atlantic Area Council region; New England and New York, which are both in the Northeast Power Coordinating Council region; California, which is in the Western Systems Coordinating Council region; and Texas, which is administered by the Electric Reliability Council of Texas. In 2001, approximately one-half of our transactions, on a megawatthour basis, were made in these markets. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets which are operated by the ISOs For sales into the spot markets administered by an ISO, the ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the ISOs may under certain circumstances require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty, could result in a material adverse impact on our financial condition, results of operations or net cash flows.

In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements.

Interest Rate Risk. We use a combination of fixed-rate and variable-rate debt to reduce interest rate exposure. Interest rate swaps may be used to adjust exposure when deemed appropriate based

upon market conditions. We also use forward-starting interest rate swaps and treasury rate locks to lock in interest rate levels in anticipation of future financings. These strategies are employed to maintain the lowest cost of capital. As of December 31, 2001, a hypothetical 10% increase in the interest rates associated with pollution control bonds would result in an approximately $1 million decrease in pre-tax earnings for 2002.

Equity Price Risk. We maintain trust funds, as required by the NRC, to fund certain costs of decommissioning our nuclear plants. As of December 31, 2001, these funds are reflected at fair value on our balance sheet. The mix of securities is designed to provide returns to be used to fund decommissioning and to compensate, including inflationary increases in decommissioning costs. However, the equity securities in the trusts are exposed to price fluctuations in equity markets, and the value of fixed rate, fixed income securities are exposed to changes in interest rates. We actively monitor the investment performance and periodically review asset allocation in accordance with our nuclear decommissioning trust fund investment guidelines. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $204 million reduction in the fair value of the trust assets.

Critical Accounting Policies

The preparation of financial statements in conformity with Generally Accepted Accounting Principles requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the reported amounts of assets and liabilities in the financial statements. The following areas represent those that management believes are particularly important to the financial statements and that require the use of estimates and assumptions to describe matters that are inherently uncertain.

Accounting for Derivative Instruments. We use derivative financial instruments primarily to manage our commodity price and interest rate risks. Derivative financial instruments are accounted for under SFAS No. 133. Accounting for derivatives continues to evolve through guidance issued by the Derivatives Implementation Group (DIG) of the Financial Accounting Standards Board. To the extent that changes by the DIG modify current guidance, including the normal purchases and normal sales determination, the accounting treatment for derivatives may change.

Energy Contracts. To manage our use of generation supply (including owned and contracted assets), we enter into contracts to purchase or sell electricity, fossil fuels, and ancillary products such as transmission rights and congestion credits, and emission allowances. These energy marketing contracts are considered derivatives under SFAS 133 unless a determination is made that they qualify for a SFAS No. 133 normal purchases and normal sales exclusion. If the exclusion applies, those contracts are not marked-to-market and are not reflected in the financial statements until delivery occurs.

The availability of the normal purchases and normal sales exclusion to specific contracts is based on a determination that excess generation is available for a forward sale and similarly a determination that at certain times generation supply will be insufficient to serve load. This determination is based on internal models that forecast customer demand and generation supply. The models include assumptions regarding customer load growth rates, which are influenced by the economy, weather and the impact of customer choice, and generating unit availability, particularly nuclear generating unit capability factors. The critical assumptions used in the determination of normal purchases and normal sales are consistent with assumptions used in the general corporate planning process.

Energy contracts that are considered derivatives may be eligible for designation as hedges. If a contract is designated as a hedge, the change in its market value is generally deferred as a component of other comprehensive income until the transaction it is hedging occurs. Conversely, the change in the market value of derivatives not designated as hedges is recorded in current period earnings. To qualify as a cash flow hedge, the fair value changes in the derivative must be expected to offset 80%-120% of

the change in fair value or cash flows of the hedged item. The effectiveness of an energy contract designated as a hedge is determined by internal models that measure the statistical correlation between the derivative and the associated hedged item.

When external quoted market prices are not available, we use the Black model, a standard industry valuation model to determine the fair value of energy derivative contracts. The valuation model uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves.

Interest Rate Derivatives. We use derivatives to manage our exposure to fluctuation in interest rates and planned future debt issuances. Hedge accounting has been used for all interest rate derivatives to date based on the probability of the transaction and the expected highly effective nature of the hedging relationship between the interest rate swap contract and the interest payment or changes in fair value of the hedged debt. Dealer quotes are available for all of our interest rate swap agreement derivatives.

Nuclear Decommissioning. Our current estimate of our nuclear facilities' decommissioning cost is $7.2 billion in current year dollars. Calculating this estimate involves significant assumptions with respect to the expected increases in decommissioning costs relative to general inflation rates, changes in the regulatory environment or regulatory requirements, and the timing of decommissioning. The estimated service life of a nuclear station is also a significant assumption because decommissioning costs are generally recognized over the life of the generating station. Cost estimates for decommissioning our nuclear facilities have been prepared by an independent engineering firm and reflect currently existing regulatory requirements and available technology. Nuclear station service lives, over which the decommissioning costs are recognized, were extended by 20 years in 2001. The life extension is subject to NRC approval of an extension of existing NRC operating licenses, which generally are 40 years. As discussed in New Accounting Pronouncements, this accounting will be affected by the adoption of SFAS No. 143, "Asset Retirement Obligations" (SFAS No. 143) effective January 1, 2003.

Estimated Service Lives of Property, Plant and Equipment. We depreciate our generation facilities and other property plant and equipment over estimated useful service lives. These estimated useful service lives are determined using three criteria: (1) economic feasibility, (2) physical feasibility and (3) functional feasibility. Economic feasibility is demonstrated through a cost/benefit analysis that an asset is economically viable and that the asset is providing an overall financial benefit. Physical feasibility represents the fact that the actual plant and equipment can operate during the defined period. Changes in physical feasibility may result from changes in the regulatory environment or environmental restrictions. Functional feasibility evaluates the impact of technology changes on the estimated service lives. In addition, nuclear power stations operate under licenses granted by the NRC. Operating licenses for our operating plants are for 40 years. We have or intend to request 20-year life extensions of these operating licenses. If not extended, nuclear plant service lives would be limited by the expiration of licenses. During 2001, we increased the estimated service lives for our operating nuclear stations, certain fossil stations and our pumped storage station. As a result of the change in service lives, depreciation and decommissioning expense decreased $90 million ($54 million, net of income taxes). Annualized savings resulting from the change will be $132 million ($79 million, net of income taxes).

Outlook

Changes in the Utility Industry. The electric utility industry in the United States remains in transition. It is moving from a fully regulated industry, consisting primarily of integrated companies combining generation, transmission and distribution, to competitive wholesale generation markets with continuing regulation of transmission and distribution. The transition has resulted in substantial

disposition of generating assets by formerly integrated companies, the creation of separate and, in some cases, stand-alone generating companies and consolidation. During 2001, however, the pace of transition slowed. This slowdown was due primarily to public and governmental reactions to issues associated with deregulation efforts in California and the collapse of the wholesale electricity market in California.

At the Federal level, FERC remains committed to the development of wholesale generation markets. Although its proposal for the development of large regional transmission organizations to facilitate markets has been delayed, it is planning an initiative to standardize wholesale markets in the United States. At the state level, concerns raised by the California experiences have stalled new retail competition initiatives and slowed the separation of generation from regulated transmission and distribution assets.

We believe that the transition in the electric utility industry will continue, albeit at a slower pace than previously, particularly at the state level. This slower transition may be reflected in reduced industry consolidation in the near term and reduced disaggregation of regulated to unregulated services. These uncertainties may limit opportunities for us to pursue our plans to expand our generation portfolio.

We also believe that competition for electric generation services has created new risks and uncertainties in the industry. Some of these risks were clearly illustrated in California—the risks of inadequate sources of generation, having load obligations without owning generation, and price volatility. The situation in California also illustrated the need for additional infrastructure to support competitive markets. The uncertainties include future prices of generation services in both the wholesale and retail markets, supply and demand volatility, and changes in customer profiles that may impact margins on various electric service offerings. These uncertainties create additional risk for participants in the industry, including us, and may result in increased volatility in operating results from year to year.

Competitive Position. We compete nationally in the wholesale electric generation markets on the basis of price and service offerings, using our generation portfolio to assure customers of energy deliverability. We have agreed to supply ComEd and PECO with their load requirements for customers through 2006 and 2010, respectively. We have contracted with Exelon Energy, the competitive retail energy services subsidiary of Exelon, to meet its load requirements pursuant to its competitive retail generation sales agreements and, in addition, we have contracts to sell energy and capacity to third parties. To the extent that our resources exceed our contractual commitments, we market these resources on a short-term basis or sell them in the spot market.

Our supply agreements with ComEd and PECO are expected to provide us with a stable source of revenue; they do not, however, provide us with any guaranteed level of revenue. As long as we have commitments to ComEd and PECO, our revenues will largely be a function of the cost of fulfilling these obligations and how much electricity is available to sell in wholesale markets after fulfilling those contracts. Generally, to the extent market prices decrease, customers may have an incentive to obtain electricity from alternative energy suppliers. To the extent that customers choose alternative energy suppliers, our revenues from contracts with ComEd and PECO will be reduced and our revenues will depend more on prices in the wholesale markets. If market prices increase substantially and our load requirements exceed our generation capacity, we may be required to purchase expensive power in the wholesale markets. Thus, any dramatic change in electricity prices combined with switching by ComEd's and PECO's customers could have an adverse effect on our results of operations or financial condition. Further, while our contracts with ComEd and PECO are currently a substantial portion of our business, we cannot predict whether they will be renewed at the end of their respective terms or, if renewed, what the terms of such renewal would be.

Our future results of operations also depend upon our ability to operate our generating facilities efficiently to meet our contractual commitments and to sell energy services in the wholesale markets. A substantial portion of our generating capacity, including all of the nuclear capacity, is base-load generation designed to operate for extended periods of time at low variable costs. Nuclear generation is currently the most cost-effective way for us to meet our commitments for sales to affiliated entities and other utilities. During 2001, our nuclear generating fleet, including AmerGen, operated at a 94.4% weighted average capacity factor. The number of refueling outages, including AmerGen, is expected to increase to eleven in 2002 from six in 2001 and, accordingly, our planned nuclear capacity factor for 2002 is 91%. Failure to achieve these capacity levels may require us to contract or purchase more expensive energy in the spot market to meet these commitments. Maintenance and capital expenditures during nuclear refueling outages are expected to increase by $80 million and $24 million, respectively, in 2002 compared to 2001 as a result of the additional nuclear refueling outages. Because of our reliance on nuclear facilities, any changes in regulations by the NRC requiring additional investments or resulting in increased operating or decommissioning costs of nuclear generating units could adversely affect our results of operations.

After we have met our contractual commitments, we sell energy in the wholesale markets. These sales expose us to the risks of rising and falling prices in those markets, and cash flows may vary accordingly. After our contracts with ComEd and PECO expire, our cash flows will largely be determined by our ability to successfully market energy, capacity and ancillary services and by wholesale prices of electricity.

We currently intend to grow our generation portfolio through investments, acquisitions and the development of new energy projects, the completion of any of which is subject to substantial risk. The competitive energy market is still evolving following deregulation and we may not be successful in anticipating appropriate market opportunities. It is possible that, due to a variety of factors, including purchase price, operating performance and future market conditions, we would be unable to achieve our goals.

Our wholesale marketing division, Power Team, uses our generation portfolio, transmission rights and expertise to ensure delivery of generation to wholesale customers under long-term and short-term contracts. Power Team is responsible for supplying the load requirements of ComEd and PECO and markets the remaining energy in the wholesale markets. Power Team also buys and sells power in the wholesale markets. Trading activities were initiated in 2001 and represent a small portion of Power Team's activity. As of December 31, 2001, trading activities accounted for less than 1% of our EBIT. Trading activities are expected to increase modestly in 2002; trading activity growth will be dependent on the continued development of the wholesale energy markets and Power Team's ability to manage trading and credit risks in those markets. The spot markets also involve the credit risks of market participants purchasing energy, which we may not be able to manage or hedge. We use financial trading primarily to complement the marketing of our generation portfolio. We intend to manage the risk of these activities through a mix of long-term and short-term supply obligations and through the use of established policies, procedures and trading limits. Financial trading, together with the effects of SFAS No. 133, may cause volatility in our future results of operations.

Other Factors

Environmental. Our operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, we are generally liable for the costs of remediating environmental contamination of property now owned by us or formerly owned by ComEd or PECO and of property contaminated by hazardous substances generated by us, ComEd or PECO.

As of December 31, 2001 and 2000, we had accrued $14 million and $16 million, respectively, for environmental investigation and remediation costs, other than decommissioning. We expect to spend $5 million for environmental remediation activities in 2002. We cannot predict whether we will incur other significant liabilities for any additional investigation and remediation costs at these or additional sites identified by us, environmental agencies or others, or whether such costs will be recoverable from third parties.

Security Issues and Other Impacts of Terrorist Actions. The events of September 11, 2001 have affected our operating procedures and costs and are expected to affect the cost and availability of the insurance coverages that we carry. The NRC has issued Safeguards and Threat Advisories to all nuclear power plant licensees, including us, requesting that they place their facilities on highest alert security status. In response to the NRC Advisories and on our own initiative, we also implemented enhanced security measures, such as increased guard forces, the erection of additional physical barriers, and heightened communication with authorities at all levels of government. In addition to the Advisories, the NRC began an initiative to perform a "top to bottom" review of its safeguards and security programs and requirements in light of the events of September 11.

On February 25, 2002, the NRC issued immediately effective orders modifying the operating licenses for all nuclear power plants to require all licensees, including us, to implement certain interim security enhancements. The security requirements imposed by the NRC's orders issued to us are currently estimated to increase capital expenditures by approximately $1 million per station for improvements, such as enhanced vehicle barriers, modifications to plant facilities and increased size of guard forces.

Insurance. We carry nuclear liability insurance. The Price-Anderson Act limits the liability of nuclear reactor owners for claims arising from a single incident. The current limit is $9.5 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. We carry the maximum available commercial insurance of $200 million. The remaining $9.3 billion is provided through mandatory participation in a financial protection pool. Price-Anderson is scheduled to expire on August 1, 2002. While there are numerous bills proposing to review Price-Anderson, we cannot predict at this time whether Congress will renew it or the effects on operations resulting from the expiration of the Price-Anderson Act.

In addition to nuclear liability insurance, we carry property damage and liability insurance for our properties and operations. Our property insurance through Nuclear Electric Insurance Limited (NEIL) provides coverage for damages caused by acts of terrorism at any of our nuclear generating stations. The terrorism endorsement to the NEIL policy specifies that the coverage applies to acts of terrorism similar to the September 11, 2001 events. In the event that one or more acts of terrorism cause accidental property damage within a 12-month period from the first accidental property damage under one or more policies for all insureds, the maximum recovery for all losses by all insureds will be an aggregate of $3.24 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity or any other source applicable to such losses. If total property losses exceed available funds under the policy, proportionate recovery is provided to cover a portion of an insured's property losses. The percentage recovery would be equal to the ratio of the insured's property losses and the total of all property losses.

NEIL also provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. The policy provides for a waiting period before recovery of costs can commence. The premium for this coverage is subject to assessment for adverse loss experience, with a maximum assessment of $46 million per year. Recovery under this insurance for terrorist acts is subject to the $3.24 billion aggregate limit and is secondary to the property insurance described above.

We are self-insured to the extent that any losses may exceed the amount of insurance maintained. NEIL provides property and business interruption insurance for our nuclear operations. In recent years,

NEIL has made distributions to its members. Our distribution for 2001 was $69 million, which was recorded as a reduction to Operating and Maintenance Expense on our Statements of Income. Due in part to the September 11, 2001 events, we cannot predict the level of future distributions, although they are expected to be lower than historical levels.

In addition, we participate in the American Nuclear Insurers Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. This program was modified, effective January 1, 1998, to provide coverage to all workers whose nuclear-related employment began on or after the commencement date of reactor operations. We will not be liable for a retrospective assessment under this new policy. However, in the event losses incurred under the small number of policies in the old program exceed accumulated reserves, a maximum retrospective assessment of up to $50 million could apply.

We do not carry any business interruption insurance other than NEIL coverage for nuclear operations. We cannot at this time predict the effect on our operations of any changes in any of these insurance policies because of terrorist acts or otherwise.

Benefit Plans. We maintain defined benefit pension plans and post-retirement welfare benefit plans. All of our employees are eligible to participate in these plans. Management employees and electing union employees, hired on or after January 1, 2001, are eligible to participate in newly established Exelon cash balance pension plans. Management employees who were active participants in the former ComEd and PECO pension plans on December 31, 2000 and remain employed by Exelon or a participating subsidiary on January 1, 2002, have the opportunity to continue to participate in the pension plan or to transfer to the cash balance plan. Participants in the cash balance plan, unlike participants in the other defined benefit plans, may request a lump-sum cash payment upon the termination of their employment, which may result in increased cash requirements from pension plan assets. We may be required to increase future funding to the pension plan as a result of these increased cash requirements.

Due to the performance of the United States debt and equity markets in 2001, the value of assets held in trusts to satisfy the obligations of pension and postretirement benefit plans has decreased. Also, as a result of the merger and corporate restructuring, there was a larger number of employees taking advantage of retirement benefits in 2001 than in other years. These factors may also result in additional future funding requirements of the pension and postretirement benefit plans.

New Accounting Pronouncements

In 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, "Business Combinations" (SFAS No. 141), SFAS No. 142 "Goodwill and Other Intangible Assets" (SFAS No. 142, SFAS No. 143, and SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144).

SFAS No. 141 requires that all business combinations be accounted for under the purchase method of accounting and establishes criteria for the separate recognition of intangible assets acquired in business combinations. SFAS No. 141 is effective for business combinations initiated after June 30, 2001. In addition, SFAS No. 141 requires that unamortized negative goodwill related to pre-July 1, 2001 purchase be recognized as change in accounting principle concurrent with the adoption of SFAS No. 142. Included on AmerGen's balance sheet is $43 million of negative goodwill, net of accumulated amortization. Upon AmerGen's adoption of SFAS No. 141 on January 1, 2002, we will recognize our appropriate share of approximately $22 million in additional income as a cumulative effect of a change in accounting principle.

SFAS No. 142 establishes new accounting and reporting standards for goodwill and intangible assets. We adopted SFAS No. 142 as of January 1, 2002. Under SFAS No. 142, effective January 1,

2002, goodwill is no longer subject to amortization. After January 1, 2002, goodwill will be subject to an assessment for impairment using a two-step fair value based test, the first step of which must be performed at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired. The first step compares the fair value of a reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step compares the carrying amount of the goodwill to the fair value of the goodwill. If the fair value of goodwill is less than the carrying amount, an impairment loss would be reported as a reduction to goodwill and a charge to operating expense, except at the transition date, when the loss would be reflected as a cumulative effect of a change in accounting principle. As of December 31, 2001, we did not have any goodwill recorded on our Consolidated Balance sheets. Accordingly, we do not expect the adoption of SFAS No. 142 to have a material impact on our financial statements.

SFAS No. 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets. We expect to adopt SFAS No. 143 on January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract or by legal construction under the doctrine of promissory estoppel. Adoption of SFAS No. 143 will change the accounting for the decommissioning of our nuclear generating plants. Currently, we record the obligation for decommissioning ratably over the lives of the plants. The January 1, 2003 adoption of this standard will require a cumulative effect adjustment effective the date of adoption to adjust plant assets and decommissioning liabilities to the values they would have been had SFAS No. 143 been employed from the in-service dates of the plants.

The effect of this cumulative adjustment will be to increase the decommissioning liability to reflect a full decommissioning obligation in current year dollars. Additionally, SFAS No. 143 will require the accrual of an asset related to the full amount of the decommissioning obligation, which will be amortized over the remaining lives of the plants. The difference between the asset recognized and the liability recorded upon adoption of the standard will be charged to earnings and recognized as a cumulative effect, net of expected regulatory recovery. The decommissioning liability to be recorded represents an obligation for the future decommissioning of the plants, and as a result, interest expense will be accrued on this liability until such time as the obligation is satisfied.

We are in the process of evaluating the impact of SFAS No. 143 on our financial statements, and cannot determine the ultimate impact of adoption at this time; however, the cumulative effect could be material to our earnings. Additionally, although over the life of the plant the charges to earnings for the depreciation of the asset and the interest on the liability will be equal to the amounts currently recognized as decommissioning expense, the timing of those charges will change and in the near-term period subsequent to adoption, the depreciation of the asset and the interest on the liability could result in an increase in expense.

SFAS No. 144 establishes accounting and reporting standards for both the impairment and disposal of long-lived assets. This statement is effective for fiscal years beginning after December 15, 2001 and provisions of this statement are generally applied prospectively. We are in the process of evaluating the impact of SFAS No. 144 on our financial statements, and we do not expect the impact to be material.

Index to Financial Statements

REPORT OF INDEPENDENT ACCOUNTANTS

To the Member and Board of Directorse
of Exelon Generation Company LLC

In our opinion, the accompanying consolidated balance sheets and related consolidated statements of income, cash flows, changes in divisional/member's equity and comprehensive income present fairly, in all material respects, the financial position of Exelon Generation Company, LLC and Subsidiary Companies (Exelon Generation) at December 31, 2001 and December 31, 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of Exelon Generation's management; our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 3 to the consolidated financial statements, Exelon Generation's parent company, Exelon Corporation, acquired Unicom Corporation on October 20, 2000 in a business combination accounted for under the purchase method of accounting. The results of the acquired generation-related business are included in the consolidated financial statements of Exelon Generation since the acquisition date.

As discussed in Note 1, Exelon Generation changed its method of accounting for derivative instruments and hedging activities effective January 1, 2001.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

March 1, 2002
Philadelphia, PA

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF INCOME

(Dollars in Millions)

	For the Years Ended December 31,		
	2001	2000	1999
Operating revenues:			
Operating revenues	$ 2,946	$ 1,723	$ 1,584
Operating revenues—affiliates	4,102	1,551	841
Total operating revenues	7,048	3,274	2,425
Operating expenses:			
Fuel and purchased power	4,093	1,845	1,205
Purchased power—affiliates	125	1	—
Operating and maintenance	1,338	754	658
Operating and maintenance—affiliates	189	46	100
Depreciation and decommissioning	282	123	125
Taxes other than income	149	64	37
Total operating expenses	6,176	2,833	2,125
Operating income	872	441	300
Other income and deductions:			
Interest expense	(115)	(41)	(12)

Equity in earnings of unconsolidated affiliates	90	4	—
Other, net	(8)	16	41
Total other income and deductions	(33)	(21)	29
Income before income taxes and cumulative effect of a change in accounting principle	839	420	329
Income taxes	327	160	125
Income before cumulative effect of a change in accounting principle	512	260	204
Cumulative effect of a change in accounting principle (net of income taxes of $7)	12	—	—
Net income	$ 524	$ 260	$ 204

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in Millions)

	For the Years Ended December 31,		
	2001	**2000**	**1999**
Cash flows from operating activities:			
Net income	$ 524	$ 260	$ 204
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and decommissioning (including amortization of nuclear fuel)	674	289	270
Provision for uncollectible accounts	15	2	—
Allowance for obsolete inventory	11	1	—
Cumulative effect of a change in accounting principle (net of income taxes)	(12)	—	—
Deferred income taxes	33	(47)	23
Amortization of investment tax credit	(8)	(13)	(12)
Earnings from equity investments	(90)	(4)	—
Net realized losses on decommissioning trust funds	127	—	—
Unrealized gains on derivative financial instruments	(30)	—	—
Interest expense on spent nuclear fuel obligation	33	10	—
Expense in contributions to long term incentive plan	—	44	—
Other operating activities	(6)	(4)	22
Changes in working capital:			
Accounts receivable	127	(158)	(54)
Accounts receivable from affiliates	104	(342)	(66)
Accounts payable to affiliates	(99)	99	—
Inventories	(22)	(58)	(5)
Accounts payable	(101)	91	(70)
Accrued expenses	61	286	114
Other current assets	2	37	(7)
Other current liabilities	(12)	(17)	10
Net cash provided by operating activities	1,331	476	429
Cash flows from investing activities:			
Investment in nuclear fuel	(336)	(112)	(95)
Investment in plant	(515)	(214)	(253)
Investment in AmerGen Energy, LLC	—	—	(39)
Investment in Sithe Energies, Inc.	—	(704)	—
Change in long-term receivable, affiliate	72	1	—
Proceeds from nuclear decommissioning trust funds	1,624	265	69
Investment in nuclear decommissioning trust funds	(1,863)	(380)	(95)
Other investment activity	(92)	(20)	(18)
Net cash used in investing activities	(1,110)	(1,164)	(431)
Cash flows from financing activities:			
Change in note payable, member	(696)	696	—
Issuance of long-term debt, net of issuance costs	820	—	6
Retirement of long-term debt	(4)	(4)	(4)
Distributions to member	(121)	—	—
Net cash (used in) provided by financing activities	(1)	692	2
Increase in cash and cash equivalents	220	4	—
Cash and cash equivalents at beginning of period	4	—	—
Cash and cash equivalents at end of period	$ 224	$ 4	$ —

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Dollars in Millions)

	December 31, 2001	December 31, 2000
Assets		
Current assets:		
Cash and cash equivalents	$ 224	$ 4
Accounts receivable, net		
Customer	316	316
Other	165	198
Affiliates	327	941
Inventories, net, at average cost:		
Fossil fuel	105	93
Materials and supplies	202	203
Other	65	38
Total current assets	1,404	1,793
Property, plant and equipment, net	1,160	831
Nuclear fuel, net	843	896
Deferred debits and other assets:		
Deferred income taxes, net	297	337
Nuclear decommissioning trust funds	3,165	3,127
Investments	859	762
Receivables from affiliate	291	363
Other	223	153
Total deferred debits and other assets	4,835	4,742
Total assets	$ 8,242	$ 8,262
Liabilities and Divisional/Member's Equity		
Current liabilities:		
Note payable to parent	$ —	$ 696
Payable to affiliate	—	99
Long-term debt due within one year	4	4
Accounts payable	588	618
Accrued expenses	303	576
Deferred income taxes	7	—
Other	171	183
Total current liabilities	1,073	2,176
Long-term debt	1,021	205
Deferred credits and other liabilities:		
Unamortized investment tax credits	234	242
Nuclear decommissioning liability for retired plants	1,353	1,301
Pension obligations	118	172
Non-pension postretirement benefits obligation	384	377
Spent nuclear fuel obligation	843	810
Other	280	369
Total deferred credits and other liabilities	3,212	3,271
Commitments and contingencies (See Note 11)	—	—
Divisional equity	—	2,610
Member's equity:		
Membership interest	2,315	
Undistributed earnings	524	
Accumulated other comprehensive income	97	—
Total divisional/member's equity	2,936	2,610
Total liabilities and divisional/member's equity	$ 8,242	$ 8,262

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

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CHANGES IN DIVISIONAL/MEMBER'S EQUITY

(Dollars in Millions)

	Divisional Equity	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income	Total Divisional/ Member's Equity
Balance, January 1, 1999	$ 746	$ —	$ —	$ —	$ 746
Net income	204				204
Balance, December 31, 1999	950				950
Net income	260				260
Contribution of net assets as a result of merger with Unicom	1,400				1,400
Balance, December 31, 2000	2,610				2,610
Formation of LLC	(2,610)	2,610			—
Non-cash distribution to member		(174)			(174)
Net income			524		524
Distribution to member		(121)			(121)
Reclassified net unrealized losses on marketable securities, net of income taxes of $22				(23)	(23)
Comprehensive income, net of income tax benefit of $171				120	120
Balance, December 31, 2001	$ —	$ 2,315	$ 524	$ 97	$ 2,936

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

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in Millions)

	For the Years Ended December 31		
	2001	2000	1999
Net income	$ 524	$ 260	$ 204
Other comprehensive income:			
SFAS 133 transitional adjustment, net of income taxes of $3	5		
Net unrealized gains on nuclear decommissioning trust funds, net of income taxes of $138	69		
Cash flow hedge fair value adjustment, net of income taxes of $29	48		
Realized loss on forward starting interest rate swap net of income taxes of $1	(2)		
Total other comprehensive income	120	—	—
Total comprehensive income	$ 644	$ 260	$ 204

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

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Dollars in Millions, unless otherwise noted)

1. Summary of Significant Accounting Policies

Description of Business

Exelon Generation Company, LLC (Exelon Generation) is a limited liability company engaged principally in the production and wholesale marketing of electricity in various regions of the United States. In 2001, the Company also began trading activities. Exelon Generation is wholly owned by Exelon Corporation (Exelon). In connection with the restructuring by Exelon to separate the regulated energy delivery business of its subsidiaries Commonwealth Edison Company (ComEd) and PECO Energy Company (PECO) from its unregulated businesses, including its generation business, Exelon Generation began operations as a separate indirect subsidiary of Exelon effective January 1, 2001. Exelon Generation has numerous wholly owned subsidiaries. These subsidiaries were primarily established to hold certain hydro electric and peaking unit facilities as well as the 49.9% interest in Sithe Energies, Inc. (Sithe) and 20.99% investment in Keystone Fuels, LLC. In addition, Exelon Generation also has a finance company subsidiary, Exelon Generation

Finance Company, LLC, which provides certain financing for Exelon Generation's other subsidiaries. Exelon Generation also owns a 50% investment in AmerGen Energy Company, LLC (AmerGen).

Basis of Presentation

The consolidated financial statements include the accounts of all majority-owned subsidiaries of Exelon Generation after the elimination of intercompany accounts and transactions. Exelon Generation consolidates its proportionate interest in jointly owned electric utility plants. Exelon Generation accounts for its investments in 20% to 50% owned entities under the equity method of accounting.

The consolidated financial statements of Exelon Generation as of December 31, 2000 and for the years ended December 31, 2000 and 1999 present the financial position, results of operations and net cash flows of the generation-related business of Exelon prior to its corporate restructuring on January 1, 2001. Exelon Generation operated as a separate business subsequent to electric-industry restructuring in Pennsylvania effective January 1, 1999. Prior to that date, Exelon (and its predecessor, PECO Energy Company) operated as a fully integrated electric and gas utility, and revenues and expenses were not separately identified in the accounting records. The consolidated financial statements are not necessarily indicative of the financial position, results of operations or net cash flows that would have resulted had the generation-related business been a separate entity during the periods presented. For periods prior to the restructuring, references to Exelon Generation mean the generation-related business of Exelon Corporation.

Certain information in these consolidated financial statements relating to the results of operations and financial condition of Exelon Generation for periods prior to Exelon's restructuring was derived from the historical financial statements of Exelon. Various allocation methodologies were employed to separate the results of operations and financial condition of the generation-related portion of Exelon's business from the historical financial statements for the periods presented prior to the restructuring. Revenues include the generation component of revenue from Exelon's operations and any generation-related revenues, such as ancillary services and wholesale energy activity. Expenses including fuel and other energy-related costs, including purchased power, operations and maintenance and depreciation and amortization, as well as assets, such as property, plant and equipment, materials and supplies and fuel, were specifically identified for Exelon Generation's operations. Various allocations were used to

disaggregate other common expenses, assets and liabilities between Exelon Generation and Exelon's other businesses, primarily the regulated transmission and distribution operations.

Management believes that these allocation methodologies are reasonable; however, had Exelon Generation existed as a separate company prior to January 1, 2001, its results could have significantly differed from those presented herein. In addition, future results of operations, financial position and net cash flows could materially differ from the historical results presented.

Segment Information

Exelon Generation operates in one business comprising its generation and marketing of energy and energy-related products in the United States.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Significant estimates have been made in the accounting for derivatives, nuclear decommissioning liabilities and estimated service lives for plant.

Revenue Recognition

Operating revenues are generally recorded as service is rendered or energy is delivered to customers. At the end of each month, Exelon Generation accrues an estimate for unbilled energy provided to its customers. Premiums received and paid on option contracts and swap arrangements are amortized to revenue and expense over the life of the contracts. Certain of these contracts are considered derivative instruments and are recorded at fair value with subsequent changes in fair value recognized as revenues and expenses unless hedge accounting is applied.

Commodity derivatives used for trading purposes are accounted for using the mark-to-market method. Under this methodology, these derivatives are adjusted to fair value, and the unrealized gains and losses are recognized in current period income.

Nuclear Fuel

The cost of nuclear fuel is capitalized and charged to fuel expense using the units of production method. Estimated costs of nuclear fuel storage and disposal at operating plants are charged to expense as the related fuel is consumed.

Emission Allowances

Emission allowances are included in deferred debits and other assets and are carried at acquisition cost and charged to fuel expense as they are used in operations. Allowances held can be used from years 2002 to 2028.

Depreciation and Decommissioning

Depreciation is provided over the estimated useful service lives of the property, plant and equipment on a straight-line basis. Nuclear power stations operate under licenses granted by the Nuclear Regulatory Commission (NRC.) Operating licenses for Exelon Generation's operating plants are for 40 years. Exelon Generation has or intends to request 20 year extensions of these operating licenses. If not extended, nuclear plant service lives would be limited by the expiration of the licenses.

The average estimated useful service lives currently being applied to determine depreciation and decommissioning expense of property, plant and equipment by type of asset are as follows:

Nuclear	60 years
Fossil	40 years
Hydro	100 years
Other	5-50 years

Exelon Generation's current estimate of the costs for decommissioning its ownership share of its nuclear generation stations is charged to operations over the expected service life of the plant. Exelon Generation's affiliates PECO and ComEd are currently recovering costs for the decommissioning of nuclear generating stations through regulated customer rates. Amounts collected for decommissioning by Exelon Generation's affiliates are remitted to Exelon Generation and are deposited in trust accounts and invested for the funding of future decommissioning costs. Exelon Generation accounts for the current period's cost of decommissioning related to generation plants previously owned by PECO by recording a charge to depreciation and decommissioning expense and a corresponding liability in accumulated depreciation concurrently with decommissioning collections.

For Exelon Generation's active nuclear generating stations previously owned by ComEd, annual decommissioning expense is based on an annual assessment of the difference between the current cost of decommissioning estimate and the decommissioning liability recorded in accumulated depreciation. The difference is amortized to depreciation and decommissioning expense on a straight-line basis over the remaining lives of the operating plants with the corresponding offset to accumulated depreciation. The current decommissioning cost estimate (adjusted annually to reflect inflation), for the former ComEd retired units recorded in deferred credits and other liabilities is accreted to depreciation and decommissioning expense. Exelon Generation believes that the amounts being recovered by ComEd and PECO from their customers through electric rates along with the earnings on the trust funds will be sufficient to fully fund its decommissioning obligations.

Research and Development

Research and development costs are charged to expense as incurred.

Capitalized Interest

Exelon Generation capitalizes the costs during construction of debt funds used to finance its construction projects. Exelon Generation recorded capitalized interest of $17 million, $2 million and $6 million in 2001, 2000 and 1999, respectively.

Income Taxes

As part of Exelon's consolidated group, Exelon Generation files a consolidated Federal income tax return with Exelon. Income taxes are allocated to each of Exelon subsidiaries within the consolidated group, including Exelon Generation, based on the separate return method.

Deferred Federal and state income taxes are provided on all temporary differences between book bases and tax bases of assets and liabilities. Investment tax credits previously used for income tax purposes have been deferred on Exelon Generation's consolidated balance sheet and are recognized in income over the life of the related property.

Cash and Cash Equivalents

Exelon Generation considers all temporary cash investments purchased with an original maturity of three months or less to be cash equivalents.

Marketable Securities

Marketable securities are classified as available-for-sale securities and are reported at fair value, with the unrealized gains and losses, net of tax, reported in other comprehensive income. The cost of these securities is determined on the basis of specific identification. At December 31, 2001 and 2000, Exelon Generation had no held-to-maturity or trading securities.

Unrealized gains and losses on marketable securities held in the nuclear decommissioning trust funds associated with the former PECO plants are reported in accumulated depreciation. Unrealized gains and losses on marketable securities held in the nuclear decommissioning trust funds associated with the former ComEd plants are reported in accumulated other comprehensive income.

Inventories

Inventories, which consist primarily of fuel and materials and supplies, are valued at the lower of cost or market and are stated on the average cost method.

Property, Plant and Equipment

Property, plant and equipment is recorded at cost. Exelon Generation evaluates the carrying value of property, plant and equipment and other long-term assets based upon current and anticipated undiscounted cash flows, and recognizes an impairment when it is probable that such estimated cash flows will be less than the carrying value of the asset. Measurement of the amount of impairment, if any, is based upon the difference between carrying value and fair value. The cost of maintenance, repairs and minor replacements of property are charged to maintenance expense as incurred. The cost and accumulated depreciation of property, plant and equipment retired or otherwise disposed of are removed from the related accounts and included in the determination of the gain or loss on disposition.

Comprehensive Income

Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to the member. Comprehensive income primarily relates to unrealized

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gains or losses on securities held in nuclear decommissioning trust funds and unrealized gains and losses on cash flow hedge instruments.

Derivative Financial Instruments

Subsequent to January 1, 2001, Exelon Generation accounts for derivative financial instruments under SFAS No. 133 "Accounting for Derivatives and Hedging Activities" (SFAS No. 133). Under the provisions of SFAS No. 133, all derivatives are recognized on the balance sheet at their fair value unless they qualify for a normal purchases or normal sales exception. Derivative financial instruments are recorded as other assets and liabilities in the consolidated balance sheet and classified as current or non-current based on the maturity date. Changes in the fair value of the derivative financial instruments are recognized in earnings unless specific hedge accounting criteria are met. A derivative financial instrument can be designated as a hedge of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge), or a hedge of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge).

Changes in the fair value of a derivative that is highly effective as, and is designated and qualifies as, a fair value hedge, along with the gain or loss on the hedged asset or liability that is attributable to the hedged risk, are recorded in earnings. Changes in the fair value of a derivative that is highly effective as, and is designated as and qualifies as a cash flow hedge are recorded in other comprehensive income, until earnings are affected by the variability of cash flows being hedged.

Pursuant to Exelon's Risk Management Policy (RMP), Exelon Generation uses derivatives to manage the utilization of its available generating capability and provisions of wholesale energy to its affiliates. Exelon Generation also utilizes energy option contracts and energy financial swap arrangements to limit the market price risk associated with forward energy commodity contracts. Exelon Generation enters into certain energy related derivatives for trading or speculative purposes. Exelon Generation may also enter into derivatives to manage its exposure to fluctuation in interest rates related to its variable rate debt instruments, changes in interest rates related to planned future debt issuances prior to their actual issuance and changes in the fair value of outstanding debt which is planned for early retirement. As part of Exelon Generation's energy marketing business, Exelon Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While these contracts are considered derivative financial instruments under SFAS No. 133, the majority of these transactions have been designated as "normal purchases" and "normal sales" and are not subject to the provisions of SFAS No. 133. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time, and price is not tied to an unrelated underlying derivative. Under these contracts Exelon Generation recognizes gains or losses when the underlying physical transaction occurs. Revenues and expenses associated with market price risk management contracts are amortized over the terms of such contracts. The remainder of these contracts are generally considered cash flow hedges under SFAS No. 133.

Additionally, during 2001, as part of the creation of Exelon Generation's energy trading operation, Exelon Generation began to enter into contracts to buy and sell energy for trading purposes, subject to limits. These contracts are recognized on the balance sheet at fair value and changes in the fair value of these derivative financial instruments are recognized in earnings.

Prior to the adoption of SFAS No. 133, Exelon Generation applied hedge accounting only if the derivative reduced the risk of the underlying hedged item and was designated at the inception of the hedge, with respect to the hedged item. Exelon Generation recognized any gains or losses on these derivatives when the underlying physical transaction affected earnings.

Contracts entered into by Exelon Generation to limit market risk associated with forward energy commodity contracts are reflected in the financial statements at the lower or cost or market using the accrual method of accounting. Under these contracts Exelon Generation recognizes any gains or losses when the underlying physical transaction affects earnings. Revenues and expenses associated with market price risk management contracts were amortized over the terms of such contracts.

Recently Issued Accounting Standards

During 2001, the FASB issued SFAS No. 141, "Business Combinations" (SFAS No. 141), No. 142, "Goodwill and Other Intangible Assets" (SFAS No. 142), No. 143, "Asset Retirement Obligations" (SFAS No. 143) and No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (SFAS No. 144).

SFAS No. 141 requires that all business combinations be accounted for under the purchase method of accounting and establishes criteria for the separate recognition of intangible assets acquired in business combinations. SFAS No. 141 is effective for business combinations initiated after June 30, 2001. In addition, SFAS No. 141 requires that unamortized negative goodwill related to pre-July 1, 2001 purchase be allocated as a pro-rata reduction of the amounts that otherwise would have been assigned to the acquired assets. If any excess remains, that remaining excess is to be recognized as an extraordinary gain concurrent with the adoption of SFAS No. 142. Included on AmerGen's balance sheet is $43 million of negative goodwill net of accumulated amortization. Upon AmerGen's adoption of SFAS No. 141 in the first quarter of 2002. Exelon Generation expects to recognize its appropriate share of approximately $22 million, pre-tax, as a cumulative effect of a change in accounting principle.

SFAS No. 142 establishes new accounting and reporting standards for goodwill and intangible assets. Exelon Generation adopted SFAS No. 142 as of January 1, 2002. Under SFAS No. 142, goodwill will no longer be subject to amortization. After January 1, 2002, goodwill will be subject to an assessment for impairment using a fair value based test at least annually, or more frequently if events or circumstances indicate that goodwill might be impaired. An impairment loss would be reported as a reduction to goodwill and a charge to operating expense, except at the transition date, when the loss would be reflected as a cumulative effect of a change in accounting principle. As of December 31, 2001, Exelon Generation has no goodwill recorded on its consolidated balance sheet.

SFAS No. 143 provides accounting requirements for retirement obligations associated with tangible long-lived assets. Exelon Generation expects to adopt SFAS No. 143 on January 1, 2003. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which there is a legal obligation to settle under existing or enacted law, statute, written or oral contract

or by legal construction under the doctrine of promissory estoppel. Adoption of SFAS No. 143 will change the accounting for the decommissioning of Exelon Generation's nuclear generating plants. Currently, Exelon Generation records the obligation for decommissioning ratably over the lives of the plants. The January 1, 2003 adoption of SFAS No. 143 will require a cumulative effect adjustment effective the date of adoption to adjust plant assets and decommissioning liabilities to the values they would have been had this standard been employed from the in-service dates of the plants. The effect of this cumulative adjustment will be to increase the decommissioning liability to reflect a full decommissioning obligation in current year dollars. Additionally, the SFAS No. 143 standard will require the accrual of an asset, to the extent allowable under the standard, related to the full amount of the decommissioning obligation, which will be amortized over the remaining lives of the plants. The net difference between the asset recognized and the liability recorded upon adoption of the standard will be charged to earnings and recognized as a cumulative effect, net of expected regulatory recovery. The decommissioning liability to be recorded represents an obligation for the future decommissioning of the plants, and as a result interest expense will be accrued on this liability until such time as the obligation is satisfied.

Exelon Generation is in the process of evaluating the impact of SFAS No. 143 on its financial statements, and cannot determine the ultimate impact of adoption at this time, however the cumulative effect could be material to Exelon's earnings. Additionally, although over the life of the plant the charges to earnings for the depreciation of the asset and the interest on the liability will be equal to the amounts currently recognized as decommissioning expense, the timing of those charges will change and in the near-term period subsequent to adoption, the depreciation of the asset and the interest on the liability could result in a significant increase in expense.

SFAS No. 144 establishes accounting and reporting standards for both the impairment and disposal of long-lived assets. SFAS No. 144 is effective for fiscal years beginning after December 15, 2001 and provisions of SFAS No. 144 are generally applied prospectively. Exelon Generation is in the process of evaluating the impact of SFAS No. 144 on its financial.

2. Merger

On October 20, 2000 Exelon became the parent corporation for PECO and ComEd as a result of the completion of the transactions contemplated by the Agreement and Plan of Exchange and Merger, as amended (Merger Agreement) among PECO, Unicom Corporation and Exelon. The Merger was accounted for using the purchase method of accounting, with PECO as acquirer.

The fair value of the assets acquired and liabilities assumed in the merger associated with the generation-related business of ComEd are summarized below:

Current assets	$	704
Property, plant and equipment		64
Nuclear fuel		669
Deferred debits and other assets		3,683
		5,120
Current liabilities		634
Deferred credits and other liabilities		3,086
		3,720
Net generation-related assets	$	1,400

Exelon Generation has included the generation-related assets and liabilities of ComEd and the related results of operations in its consolidated financial statements beginning October 20, 2000. Exelon Generation's Statement of Changes in Member's Equity reflects the generation-related impacts of the Merger as a capital contribution from Exelon.

3. Corporate Restructuring

During January 2001, Exelon undertook a corporate restructuring to separate its generation and other competitive businesses from its regulated energy delivery businesses conducted by ComEd and PECO. As part of the restructuring, the generation-related operations, employees, assets, liabilities, and certain commitments of Exelon Corporation were transferred to Exelon Generation.

The assets and liabilities transferred to Exelon Generation as of January 1, 2001 were as follows:

Assets		
Current assets	$	1,285
Property, plant and equipment		831
Nuclear fuel		896
Nuclear decommissioning trust funds		3,127
Investments		762
Deferred income taxes		337
Note receivable from affiliate		363
Other noncurrent assets		153
Total assets transferred		7,754
Liabilities		
Note payable to member		696
Current liabilities		1,146
Long-term debt		205
Decommissioning obligation for retired plants		1,301
Other noncurrent liabilities		1,970
Total liabilities transferred		5,318
Net assets transferred	$	2,436

On January 1, 2001, a non-cash distribution of $174 million was made in connection with the elimination of certain intercompany transactions.

In connection with the restructuring, ComEd and PECO also assigned their respective rights and obligations under various power purchase and fuel supply agreements to Exelon Generation. Additionally, Exelon Generation entered into power purchase agreements (PPAs) to supply the capacity and energy requirements of ComEd and PECO.

4. Equity Investments

Sithe Energies, Inc.

On December 18, 2000, Exelon Generation acquired 49.9% of the outstanding common stock of Sithe for $696 million in cash and $8 million of acquisition costs. Sithe, headquartered in New York, is a leading independent power producer, with ownership interests in 27 facilities in North America. Sithe has net generation capacity of 3,371 MW, primarily in New York and Massachusetts, 2,651 MW under construction and 2,400 MW in advanced development.

Beginning December 18, 2002, Exelon Generation will have the right to purchase all (but not less than all) of the remaining outstanding shares of the Sithe common stock. The option expires on December 18, 2005. In addition, each of Sithe's other stockholder groups will have the right to require us to purchase all (but not less than all) of its shares during the same period in which Exelon Generation can exercise its option. At the end of that period, if no stockholder has exercised its option,

Exelon Generation will have a one-time option to purchase shares from the other stockholders to bring its holdings to 50.1% of the total outstanding shares. If Exelon Generation exercise its option or if all the stockholder groups exercise their put rights, the purchase price for 70% of the remaining 50.1% of the Sithe stock will be set at a fair market value plus a 10% premium in the case of a call or 10% discount in the case of a put, subject to a floor of $430 million and a ceiling of $650 million, and the remaining portion will be valued at fair market value, subject to a floor price of $141 million and a ceiling price of $330 million, plus, in each case, interest accrued from the beginning of the exercise period.

If Exelon Generation increases its ownership in Sithe to 50.1% or more, Sithe will become a consolidated subsidiary and Exelon Generation's financial results will include Sithe's financial results from the date of purchase. At December 31, 2001, Sithe had total assets of $4.2 billion and long-term debt of $2.3 billion, including $2.1 billion of non-recourse project debt, and excluding any non-recourse project debt associated with Sithe's equity investments. For the year ended December 31, 2001 Sithe had revenues of approximately $1 billion. In December 2001, Sithe entered into a new 18-month corporate credit facility for $500 million expiring in June 2003. As of December 31, 2001 Sithe had drawn approximately $176 million under this facility and extended approximately $161 million in letters of credit.

Exelon Generation's investment in Sithe as of December 31, 2001 and 2000 was $725 million and $704 million, respectively.

AmerGen Energy Company, LLC

Exelon Generation and British Energy, Inc, a wholly owned subsidiary of British Energy, plc, each own a 50% equity interest in AmerGen Energy Company, LLC (AmerGen). Established in 1997, AmerGen was formed to pursue opportunities to acquire and operate nuclear generation facilities in the North America. Currently, AmerGen owns and operates three nuclear generation facilities: Clinton Power Station (Clinton) located in Illinois, Three Mile Island (TMI) Unit 1 located in Pennsylvania, and Oyster Creek, which was acquired in August 2000, located in New Jersey. Oyster Creek was acquired from GPU, Inc. (GPU) for $10 million. Under the terms of the purchase agreement, GPU agreed to fund outage cots of $89 million, including the cost of fuel, for a refueling outage that occurred in 2000. AmerGen is repaying these costs to GPU in equal annual installments through 2009. In addition, AmerGen assumed full responsibility for the ultimate decommissioning of Oyster Creek. At the closing of the sale, GPU provided funding for the decommissioning trust of $440 million. In conjunction with this acquisition, AmerGen has received a fully funded decommissioning trust fund which has been computed assuming the anticipated costs to appropriately decommission Oyster Creek discounted to net present value using the NRC's mandated rate of 2%. As part of each acquisition, AmerGen entered into a power sales agreement with the seller. The agreement with the seller for Clinton calls for Exelon Generation to sell 75% of the output back to Illinois Power for a term expiring at the end of 2005. The agreements with the seller of TMI and Oyster Creek are for all of the output expiring in 2001 and 2003, respectively.

AmerGen maintains a nuclear decommissioning trust fund for each of its plants in accordance with NRC regulations and believes that amounts in these trust funds, together with the investment earnings

thereon and additional contributions for Clinton from Illinois Power, will be sufficient to meet its decommissioning obligations.

Exelon Generation's investment in AmerGen as of December 31, 2001 and 2000 was $113 million and $44 million, respectively.

The table below presents summarized financial information for Sithe and AmerGen, Exelon Generation's unconsolidated equity affiliates:

	Year Ended December 31,		
Income Statement Information	**2001**	**2000**	**1999**
Operating revenues	$ 1,691	$ 1,675	$ 15
Operating income	297	546	4
Income before extraordinary items and cumulative effect of change in accounting principle	(8)	254	4
Net income	$ (8)	$ 254	$ 4

	Year Ended December 31,	
Balance Sheet Information	**2001**	**2000**
Current assets	$ 745	$ 588
Noncurrent assets	5,126	3,930
Total assets	$ 5,871	$ 4,518
Current liabilities	591	1,072
Noncurrent liabilities	3,714	2,025
Members' capital	80	80
Undistributed earnings (deficit)	155	(1)
Additional paid-in capital	735	735
Retained earnings	647	602
Accumulated other comprehensive income (loss)	(51)	5
Total capitalization and liabilities	$ 5,871	$ 4,518

5. Property, Plant and Equipment

A summary of property, plant and equipment by classification is as follows:

	December 31,	
	2001	**2000**
Generation plant	$ 4,344	$ 4,142
Construction work-in-progress	610	380
Total property, plant and equipment	4,954	4,522
Less: accumulated depreciation (including decommissioning costs for active nuclear stations)	3,794	3,691
Property, plant and equipment, net	$ 1,160	$ 831

6. Jointly Owned Facilities—Property, Plant and Equipment

Exelon Generation's ownership interest in jointly owned generation plant at December 31, 2001 and 2000 were as follows:

	2001				
Plant	**Peach Bottom**	**Salem**	**Keystone**	**Conemaugh**	**Quad Cities**
Operator	**Exelon Generation**	**PSEG Nuclear**	**Sithe**	**Sithe**	**Exelon Generation**
Participating Interest	50.00%	42.59%	20.99%	20.72%	75.00%
Generation plant	$ 387	$ 12	$ 121	$ 193	$ 96
Construction work-in-progress	13	53	13	12	52
Total property, plant and equipment	400	65	134	205	148
Accumulated depreciation	220	4	98	124	10
Property, plant and equipment, net	$ 180	$ 61	$ 36	$ 81	$ 138

	2000				
Plant	**Peach Bottom**	**Salem**	**Keystone**	**Conemaugh**	**Quad Cities**
Operator	**Exelon Generation**	**PSEG Nuclear**	**Sithe**	**Sithe**	**Exelon Generation**
Participating Interest	46.25%	42.59%	20.99%	20.72%	75.00%
Generation plant	$ 378	$ 3	$ 120	$ 190	$ 84
Construction work-in-progress	41	41	4	10	38
Total property, plant and equipment	419	44	124	200	122
Accumulated depreciation	214	3	94	118	2
Property, plant and equipment, net	$ 205	$ 41	$ 30	$ 82	$ 120

Exelon Generation's undivided ownership interests are financed with Exelon Generation funds and, when placed in service, all operations are accounted for as if such participating interests were wholly owned facilities.

On September 30, 1999, PECO reached an agreement to purchase an additional 7.51% ownership interest in Peach Bottom Atomic Power Station (Peach Bottom) from Atlantic City Electric Company

(ACE) and Delmarva Power & Light Company (DPL) for $18 million. With the purchase of the additional ownership interest in Peach Bottom, Exelon Generation received a transfer of $47 million representing ACE and DPL's decommissioning trust funds and the related liability for the station. As a result of the restructuring, the purchase agreement has been assigned to Exelon Generation. DPL's 3.755% interest was purchased in December 2000 by PECO and transferred to Exelon Generation as part of the restructuring. The purchase of ACE's 3.755% ownership interest was completed in October 2001.

7. Nuclear Decommissioning and Spent Fuel Storage

Nuclear Decommissioning

Exelon Generation has an obligation to decommission its nuclear power plants. Exelon Generation's current estimate of its nuclear facilities' decommissioning cost for its owned nuclear plants is $7.2 billion in current year (2002) dollars. Nuclear decommissioning activity occurs primarily after the plants retirement and is currently estimated to begin in 2031. Exelon Generation's Zion Station permanently ceased power generation operations in 1998. The plant is currently being maintained in a secure and safe condition until final decommissioning, which is scheduled to begin in 2013. Decommissioning costs are currently recoverable through the regulated rates of ComEd and PECO. Exelon Generation collected $102 million in 2001 from ComEd and PECO. At December 31, 2001, the decommissioning liability recorded in accumulated depreciation and deferred credits and other liabilities was $2.7 billion and $1.3 billion, respectively. At December 31, 2000, the decommissioning liability recorded in Accumulated Depreciation and deferred credits and other liabilities was $2.6 billion and $1.3 billion, respectively. In order to fund future decommissioning costs, at December 31, 2001 and 2000, Exelon Generation held $3.2 billion and $3.1 billion, respectively, in trust accounts which are included as investments in Exelon Generation's Consolidated Balance Sheets at their fair market value. These trust funds are either qualified or non-qualified. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a "qualified fund." Contributions made into a qualified fund are tax deductible. Exelon Generation believes that the amounts being recovered from customers through regulated rates and earnings on nuclear decommissioning trust funds will be sufficient to fully fund its decommissioning obligations.

In connection with the transfer by ComEd of its nuclear generating stations to Exelon Generation, ComEd asked the Illinois Commerce Commission (ICC) to approve the continued recovery of decommissioning costs after the transfer. On December 20, 2000, the ICC issued an order finding that the ICC has the legal authority to permit ComEd to continue to recover decommissioning costs from customers for the six-year term of the power purchase agreements between ComEd and Exelon Generation. Under the ICC order, ComEd is permitted to recover $73 million per year from customers for decommissioning for the years 2001 through 2004. In 2005 and 2006, ComEd can recover up to $73 million annually, depending upon the portion of the output of the former ComEd nuclear stations that ComEd purchases from Exelon Generation. Under the ICC order, subsequent to 2006, there will be no further recoveries of decommissioning costs from customers. The ICC order also provides that any surplus funds after the nuclear stations are decommissioned must be refunded to customers. The ICC order is currently pending on appeal in the Illinois Appellate Court.

Exelon Generation recorded a receivable from ComEd of approximately $440 million representing ComEd's legal requirement to remit funds to Exelon Generation upon collection from customers, and

for collections from customers prior to the establishment of external decommissioning trust funds in 1989 to be remitted to Exelon Generation for deposit into the decommissioning trusts through 2006. Unrealized gains and losses on decommissioning trust funds (based on the market value of the assets on the Merger date, in accordance with purchase accounting) had previously been recorded in accumulated depreciation. As a result of the transfer of the ComEd nuclear plants to Exelon Generation and the ICC order limiting the regulated recoveries of decommissioning costs, net unrealized losses of $23 million (net of income taxes) at that date were reclassified to accumulated other comprehensive income.

All subsequent realized gains and losses on these decommissioning trust funds' assets are based on the cost basis of the trust fund assets established on the Merger date and are reflected in Other Income and Deductions in Exelon Generation's Consolidated Statements of Income.

Nuclear decommissioning costs associated with the nuclear generating stations formerly owned by PECO continue to be recovered currently through rates charged by PECO to regulated customers these amounts are remitted to Exelon Generation as allowed by the Pennsylvania Public Utility Commission.

Spent Fuel Storage

Under the Nuclear Waste Policy Act of 1982 (NWPA), the U.S. Department of Energy (DOE) is responsible for the selection and development of repositories for, and the disposal of, spent nuclear fuel and high-level radioactive waste (SNF). ComEd and PECO, as required by the NWPA, each signed a contract with the DOE (Standard Contract) to provide for disposal of SNF from their respective nuclear generating stations. In accordance with the NWPA and the Standard Contract, ComEd and PECO pay the DOE one mill ($.001) per kilowatt-hour of net nuclear generation for the cost of nuclear fuel long-term storage and disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contract required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 1998. The DOE, however, failed to meet that deadline and its performance is expected to be delayed significantly. The DOE's current estimate for opening an SNF facility is 2010. This extended delay in SNF acceptance by the DOE has led to Exelon Generation's use of dry storage at its Dresden and Peach Bottom Units and its consideration of dry storage at other units.

In July 2000, PECO entered into an agreement with the DOE relating to Peach Bottom nuclear generating unit to address the DOE's failure to begin removal of SNF in January 1998 as required by the Standard Contract. Under that agreement, the DOE agreed to provide credits against future contributions to the Nuclear Waste Fund over the next ten years to compensate for SNF storage costs incurred as a result of the DOE's breach of the contract. The agreement also provides that the DOE will take title to the SNF upon request and the interim storage facility at Peach Bottom provided certain conditions are met.

In November 2000, eight utilities with nuclear power plants filed a Joint Petition for Review against the DOE with the United States Court of Appeals for the Eleventh Circuit seeking to invalidate that portion of the agreement providing for credits against nuclear waste fund payments on the ground that such provision is a violation of the NWPA. PECO intervened as a defendant in that case, which is ongoing. In April, 2001, an individual filed suit against the DOE with the United States District Court for the Middle District of Pennsylvania seeking to invalidate the agreement on the grounds that the DOE has violated the National Environmental Policy Act and the Administrative Procedure Act. PECO

intervened as a defendant and moved to dismiss the complaint. The Court has not yet ruled on the motion to dismiss.

The Standard Contract with the DOE also requires that PECO and ComEd pay the DOE a one-time fee applicable to nuclear generation through April 6, 1983. PECO's fee has been paid. Pursuant to the Standard Contract, ComEd elected to defer payment of the one-time fee of $277 million, with interest accruing to the date of payment, just prior to the first delivery of SNF to the DOE. As of December 31, 2001, the liability for the one-time fee with interest was $843 million.

The liabilities for spent nuclear fuel disposal costs, including the one-time fee, were transferred to Exelon Generation as part of the corporate restructuring.

8. Long-Term Debt

Long-term debt is comprised of the following:

	Rates	Maturity Date	December 31, 2001	December 31, 2000
Notes payable	7.25%	2003-2004	$ 9	$ 14
Senior unsecured notes	6.95%	2011	699	—
Pollution control notes	2.10%—2.70%	2016-2034	317	195
Total long-term debt			1,025	209
Due within one year			(4)	(4)
Long-term debt			$ 1,021	$ 205

Long-term debt maturities in the period 2002 through 2006 and thereafter are as follows:

2002	$ 4
2003	4
2004	1
2005	—
2006	—
Thereafter	1,016
	$ 1,025

In May 2001, Exelon Generation entered into a forward-starting interest rate swap, with an aggregate notional amount of $700 million, to hedge the interest rate risk related to the anticipated issuance of debt. On June 11, 2001, Exelon Generation issued $700 million of senior unsecured notes with a maturity date of June 15, 2011 and an interest rate of 6.95% and closed the forward-starting interest rate swap. The aggregate loss on the settlement of the swap of $2 million, net of related income taxes, was classified in Accumulated Other Comprehensive Income and is being amortized to interest expense over the life of the debt.

Also during 2001, Exelon Generation issued $121 million of Pollution Control Revenue Refunding Bonds at an average variable commercial paper interest rate of 2.685% with maturities of 20 to 33 years. The proceeds from these offerings were used to refund tax-exempt debt previously issued by PECO. The transaction was accounted for as a distribution to the member.

Exelon Generation, together with Exelon, ComEd and PECO, entered into a $1.5 billion 364 day unsecured revolving credit facility on December 12, 2001 with a group of banks. As of December 31, 2001, Exelon Generation did not meet the requirements to borrow under this facility.

9. Income Taxes

Income tax expense (benefit) is comprised of the following components for the years ended December 31:

	2001	2000	1999
Included in operations:			
Federal:			
Current	$ 253	$ 177	$ 92
Deferred	15	(38)	18
Investment tax credit, net	(8)	(13)	(12)
State:			
Current	51	43	22
Deferred	16	(9)	5
	$ 327	$ 160	$ 125
Included in cumulative effect of a change in accounting principle:			
Federal—deferred	$ 6	$ —	$ —
State—deferred	1	—	—
	$ 7	—	—

The effective income tax rate differed from the Federal statutory rate for the years ended December 31 principally due to the following:

	2001	2000	1999
Income taxes on above at Federal statutory rate of 35%	35.0%	35.0%	35.0%
Increase (decrease) due to:			
State income taxes, net of Federal income tax benefit	5.2%	5.0%	5.2%
Nuclear decommissioning trust income	(0.6)%	0.0%	—
Amortization of investment tax credit	(0.6)%	(1.9)%	(2.1)%
Other, net	—	—	(0.1)%
Effective income tax rate	39.0%	38.1%	38.0%

The tax effect of temporary differences giving rise to Exelon Generation's deferred tax assets and liabilities as of December 31, 2001 and 2000 are presented below:

	2001	2000
Deferred tax assets:		
Decommissioning and decontamination obligations	$ 856	$ 455
Deferred pension and postretirement obligations	236	227
Deferred investment tax credits	93	96
Other, net		110
Total deferred tax assets	1,185	888
Deferred tax liabilities:		
Plant basis difference	(709)	(397)
Unrealized gains on derivative financial instruments	(30)	—
Decommissioning and decontamination obligations	(100)	(118)
Emission allowances	(44)	(36)
Other, net	(12)	—
Total deferred tax liabilities	(895)	(551)
Deferred income taxes net on the balance sheet	$ 290	$ 337

Prior to 2001, the offsetting deferred tax assets and liabilities resulting from decommissioning and decontamination assets and obligations, accounted for as regulatory assets and liabilities, were recorded within the plant basis difference caption above. As a result of the corporate restructuring, on January 1, 2001, the decommissioning and decontamination obligations were transferred to Exelon Generation. The deferred tax asset related to the decommissioning and decontamination obligation is no longer recorded in the plant basis difference caption with the regulatory assets and liabilities.

Included in accrued expenses on Exelon Generation's consolidated balance sheets at December 31, 2001 and 2000 was approximately $245 and $334 million current taxes payable due to the member.

The Internal Revenue Service and certain state tax authorities are currently auditing certain tax returns of Exelon's predecessor entities, Unicom and PECO. The current audits are not expected to have an adverse effect on financial condition or results of operations of Exelon Generation.

10. Employee Benefits

Exelon Generation has adopted defined benefit pension plans and postretirement welfare plans sponsored by Exelon. All Exelon Generation employees are eligible to participate in these plans. Essentially all Exelon Generation management employees, and electing union employees, hired on or after January 1, 2001 are eligible to participate in the newly established Exelon cash balance pension plan. Management employees who were active participants in the pension plans on December 31, 2000 and remain employed on January 1, 2002, will have the opportunity to continue to participate in the pension plans or to transfer to the cash balance plan. Benefits under these pension plans generally reflect each employee's compensation, years of service, and age at retirement. Funding is based upon actuarially determined contributions that take into account the amount deductible for income tax

purposes and the minimum contribution required under the Employee Retirement Income Security Act of 1974, as amended. The following tables provide a reconciliation of benefit obligations, plan assets, and funded status of Exelon Generation's proportionate interest in the Exelon plans.

	Pension Benefits		Other Postretirement Benefits	
	2001	2000	2001	2000
Change in Benefit Obligation:				
Net benefit obligation at beginning of year	$ 2,757	$ 893	$ 1,144	$ 351
Service cost	37	17	17	11
Interest cost	166	91	70	33
Plan participants' contributions	—	—	2	—
Plan amendments	19	—	(105)	—
Actuarial (gain)loss	102	102	72	77
Acquisitions	—	1,689	—	670
Curtailments/Settlements	(16)	(32)	—	2
Special accounting costs	13	90	2	25
Gross benefits paid	(202)	(93)	(70)	(25)
Net benefit obligation at end of year	$ 2,876	$ 2,757	$ 1,132	$ 1,144
Change in Plan Assets:				
Fair value of plan assets at beginning of year	$ 2,908	$ 1,296	$ 635	$ 108
Actual return on plan assets	(111)	82	(7)	(6)
Employer contributions	14	1	40	40
Plan participants' contributions	—	—	2	1
Acquisitions	—	1,622	—	517
Gross benefits paid	(202)	(93)	(70)	(25)
Fair value of plan assets at end of year	$ 2,609	$ 2,908	$ 600	$ 635
Funded status at end of year	$ (267)	$ 151	$ (532)	$ (509)
Miscellaneous adjustment	—	—	—	3
Unrecognized net actuarial (gain)loss	110	(347)	207	75
Unrecognized prior service cost	46	33	(105)	—
Unrecognized net transition obligation (asset)	(7)	(9)	46	54
Net amount recognized at end of year	$ (118)	$ (172)	$ (384)	$ (377)

	Pension Benefits			Other Postretirement Benefits		
	2001	2000	1999	2001	2000	1999
Weighted-average assumptions as of December 31,						
Discount rate	7.35%	7.60%	8.00%	7.35%	7.60%	8.00%
Expected return on plan assets	9.50%	9.50%	9.50%	9.50%	8.00%	8.00%
Rate of compensation increase	4.00%	4.30%	5.00%	4.00%	4.30%	5.00%
Health care cost trend on covered charges	N/A	N/A	N/A	10.00% decreasing to ultimate trend of 4.5% in 2008	7.00% decreasing to ultimate trend of 5.0% in 2005	8.00% decreasing to ultimate trend of 5.0% in 2006

	Pension Benefits			Other Postretirement Benefits		
	2001	2000	1999	2001	2000	1999
Components of net periodic benefit cost (benefit):						
Service cost	$ 37	$ 17	$ 13	$ 17	$ 11	$ 8
Interest cost	166	91	65	70	33	20
Expected return on assets	(215)	(131)	(94)	(46)	(15)	(6)
Amortization of:						
Transition obligation (asset)	(2)	(2)	(2)	4	4	4
Prior service cost	4	3	2	(5)	—	—
Actuarial (gain) loss	(11)	(11)	(3)	—	—	—
Curtailment charge (credit)	(6)	(5)	—	4	10	—
Settlement charge (credit)	(3)	(7)	—	—	—	—
Net periodic benefit cost (benefit)	$ (30)	$ (45)	$ (19)	44	$ 43	$ 26
Special accounting costs	$ 13	$ 90	$ —	$ 2	$ 25	$ —

Sensitivity of retiree welfare results		
Effect of a one percentage point increase in assumed health care cost trend on total service and interest cost components	$	15
on postretirement benefit obligation	$	135
Effect of a one percentage point decrease in assumed health care cost trend on total service and interest cost components	$	(12)
on postretirement benefit obligation	$	(117)

Prior service cost is amortized on a straight-line basis over the average remaining service period of employees expected to receive benefits under the plans.

Special accounting costs in 2000 of $90 million include $42 million for separation benefits and $48 million for plan enhancements. Exelon Generation provides certain health care and life insurance benefits for retired employees through plans sponsored by Exelon. In 2001, Exelon amended the postretirement medical benefit plan to change the eligibility requirement of the plan to cover only employees who retire with 10 years of service after age 45 rather than with 10 years of service and having attained the age of 55. Welfare benefits for active employees are provided by several insurance policies or self-funded plans whose premiums or contributions are based upon the benefits paid during the year.

Exelon Generation has savings plans for the majority of its employees. The plans allow employees to contribute a portion of their pretax income in accordance with specified guidelines. Exelon Generation matches a percentage of the employee contribution up to certain limits. The cost of Exelon Generation's matching contribution to the savings plans totaled $15 million in 2001.

Exelon Generation participates in a 401(k) Savings Plan for Employees sponsored by Exelon. The plan allows employees to contribute a portion of their pretax income in accordance with specified guidelines. Exelon Generation matches a percentage of employee contributions to the plan up to certain limits. Exelon Generation expensed matching contributions to the plan totaling $23 million for 2001, $7 million for 2000 and $3 million for 1999.

11. Commitments and Contingent Liabilities

Capital Expenditures

Generation's estimated capital expenditures for 2002 are as follows:

		(in millions)
Production Plant	$	392
Nuclear Fuel		432
Investments		254
Total	$	1,078

Capital expenditures for production include expenditures to increase capacity of existing plants.

Capital Commitments

Exelon Generation has committed to provide AmerGen with capital contributions equivalent to 50% of the purchase price of any acquisitions AmerGen makes in 2002 and Exelon Generation and British Energy have each agreed to provide up to $100 million to AmerGen at any time for operating expenses.

Pending Acquisition

In December 2001, Exelon Generation agreed to purchase two generation plants located in the Dallas-Fort Worth metropolitan area from TXU Corp. (TXU) to expand its presence in the Texas region. The $443 million purchase (not included in above table) of the two natural-gas and oil-fired plants, to be funded through available cash and commercial paper proceeds, will add approximately 2,300 megawatts (MW) capacity. The transaction includes a power purchase agreement for TXU to purchase power during the months of May through September from 2002 through 2006. During the periods covered by the power purchase agreement, TXU will make fixed capacity payments and will provide fuel to Exelon Generation in return for exclusive rights to the energy and capacity of the generation plants. The closing of the acquisition is contingent upon receipt of the necessary regulatory approvals and is anticipated to occur in the second quarter of 2002.

Nuclear Insurance Coverages and Assessments

The Price-Anderson Act limits the liability of nuclear reactor owners for claims that could arise from a single incident. The current limit is $9.5 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. Exelon Generation carries the maximum available commercial insurance of $200 million and the remaining $9.3 billion is provided through mandatory participation in a financial protection pool. Under the Price-Anderson Act, all nuclear reactor licensees can be assessed up to $89 million per reactor per incident, payable at no more than $10 million per reactor per incident per year. This assessment is subject to inflation and state premium taxes. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims. Price-Anderson is scheduled to expire on August 1, 2002. Although replacement legislation has been proposed from time to time, Exelon Generation is unable to predict whether replacement legislation will be enacted.

Exelon Generation carries property damage, decontamination and premature decommissioning insurance for each station loss resulting from damage to its nuclear plants. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Exelon Generation is required by the NRC to maintain, to provide for decommissioning the facility. Exelon Generation is unable to predict the timing of the availability of insurance proceeds to Exelon Generation and the amount of such proceeds which would be available. Under the terms of the various insurance agreements, Exelon Generation could be assessed up to $121 million for losses incurred at any plant insured by the insurance companies. In the event that one or more acts of terrorism cause accidental property damage within a twelve month period from the first accidental property damage under one or more policies for all insureds, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity, and any other source, applicable to such losses.

Additionally, Exelon Generation is a member of an industry mutual insurance company that provides replacement power cost insurance in the event of a major accidental outage at a nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Exelon Generation's maximum share of any assessment is $46 million per year.

In addition, Exelon Generation participates in the American Nuclear Insurers Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. This program was modified, effective January 1, 1998, to provide coverage to all workers whose "nuclear-related employment" began on or after the commencement date of reactor operations. Exelon Generation will not be liable for a retrospective assessment under this new policy. However, in the event losses incurred under the small number of policies in the old program exceed accumulated reserves, a maximum retroactive assessment of up to $50 million could apply.

Exelon Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon Generation's financial condition and results of operations.

Energy Commitments

Exelon Generation's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity, and long, intermediate and short-term contracts. Exelon Generation maintains a net positive supply of energy and capacity, through ownership of generation assets and power purchase and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generation units. Exelon Generation has also contracted for access to additional generation through bilateral long-term power purchase agreements. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature —similar to asset ownership. Exelon Generation enters into power purchase agreements with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Exelon Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The intent and business objective for the use of its capital assets and contracts are to provide Exelon Generation with physical power supply to enable it to deliver energy to meet customer needs. Exelon primarily uses financial contracts in its wholesale marketing activities for hedging purposes. Exelon also uses financial contracts to manage the risk surrounding trading for profit activities.

Exelon Generation has entered into bilateral long-term contractual obligations for sales of energy to ComEd, PECO and other load-serving entities, including electric utilities, municipalities, electric cooperatives, and retail load aggregators. Exelon Generation also enters into contractual obligations to deliver energy to wholesale market participants who primarily focus on the resale of energy products for delivery. Exelon Generation provides delivery of its energy to these customers through rights for firm transmission. In addition, Exelon Generation has entered into long-term power purchase agreements with independent power producers (IPP) under which Exelon Generation makes fixed capacity payments to the IPP in return for exclusive rights to the energy and capacity of the generation units for a fixed period.

At December 31, 2001, Exelon Generation's long-term commitments, relating to the purchase and sale of energy, capacity and transmission rights from affiliated and unaffiliated entities are as expressed in the following tables:

	Unaffiliated				Affiliated	
	Power Purchases	Power Sales	Capacity Purchases	Transmission Rights Purchases	Power Sale/ Capacity	Power Purchases
2002	$ 295	$ 1,803	$ 1,005	$ 139	$ 4,047	$ 256
2003	84	666	1,214	31	4,220	261
2004	31	219	1,222	15	4,094	315
2005	23	139	406	15	4,018	241
2006	9	58	406	5	3,974	241
Thereafter	150	22	3,657	—	6,207	2,171
Total	$ 592	$ 2,907	$ 7,910	$ 205	$ 26,560	$ 3,485

Included in Exelon Generation's long-term commitments are PPAs with Midwest Generation, LLC Midwest Generation for the purchase of capacity from its coal fired stations, in declining amounts through 2004. Contracted capacity and capacity available through the exercise of an annual option are as follows (in megawatts):

	Contracted Capacity	Available Option Capacity
2002	4,013	1,632
2003	1,696	3,949
2004	1,696	3,949

The agreements with Midwest Generationa also provide for the option to purchase 2,698 megawatts of oil and gas-fired capacity, and 944 megawatts of peaking capacity, subject to reduction.

Exelon Generation has entered into PPAs with AmerGen, under which it will purchase all the energy from Unit No. 1 at TMI after December 31, 2001 through December 31, 2014. Under a 1999 PPA, Generation will purchase from AmerGen all of the residual energy from Clinton through December 31, 2002. Currently, the residual output approximates 25% of the total output of the Clinton facility.

Environmental Issues

Exelon Generation's operations have in the past and may in the future require substantial capital expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, Exelon Generation is generally liable for the costs of remediating environmental contamination of property now owned and of property contaminated by hazardous substances generated by Exelon Generation.

As of December 31, 2001, Exelon Generation had accrued $14 million for environmental investigation and remediation costs. Exelon Generation cannot reasonably estimate whether it will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by Exelon Generation, environmental agencies or others, or whether such costs will be recoverable from third parties.

Leases

Minimum future operating lease payments, including lease payments for real estate, rail cars and office equipment, as of December 31, 2001 were:

2002	$ 28
2003	37
2004	26
2005	32
2006	32
Thereafter	527
Total minimum future lease payments	$ 682

Rental expense under operating leases totaled $29 million $19 million and $18 million for the year ended December 31, 2001, 2000 and 1999, respectively.

Litigation

Cajun Electric Power Cooperative, Inc. On May 27, 1998, the United States Department of Justice, on behalf of the Rural Utilities Service and the Chapter 11 Trustee for the Cajun Electric Power Cooperative, Inc. (Cajun), filed an action claiming breach of contract against PECO in the United States District Court for the Middle District of Louisiana arising out of PECO's termination of the contract to purchase Cajun's interest in the River Bend nuclear power plant. Effective with the corporate restructuring, Exelon Generation has agreed to assume any liability and obligation arising from this litigation. During 2001, the parties reached a settlement of the dispute, and Exelon Generation made a payment of $14 million to Cajun.

Cotter Corporation. During 1989 and 1991, actions were brought in federal and state courts in Colorado against ComEd and its subsidiary, Cotter Corporation (Cotter), seeking unspecified damages and injunctive relief based on allegations that Cotter permitted radioactive and other hazardous material to be released from its mill into areas owned or occupied by the plaintiffs, resulting in property damage and potential adverse health effects. In 1994, a federal jury returned nominal dollar verdicts against Cotter on eight plaintiffs' claims in the 1989 cases, which verdicts were upheld on appeal. The remaining claims in the 1989 actions were settled or dismissed. In 1998, a jury verdict was rendered against Cotter in favor of 14 of the plaintiffs in the 1991 cases, totaling approximately $6 million in compensatory and punitive damages, interest and medical monitoring. On appeal, the Tenth Circuit Court of Appeals reversed the jury verdict, and remanded the case for new trial. These plaintiffs' cases were consolidated with the remaining 26 plaintiffs' cases, which had not been tried. The consolidated trial was completed on June 28, 2001. The jury returned a verdict against Cotter and

awarded $16.3 million in various damages. On November 20, 2001, the District Court entered an amended final judgment which included an award of both pre-judgment and post-judgment interests, costs, and medical monitoring expenses which total $43.3 million. This matter is being appealed by Cotter in the Tenth Circuit Court of Appeals. Cotter will vigorously contest the award.

In November 2000, another trial involving a separate sub-group of 13 plaintiffs, seeking $19 million in damages plus interest was completed in federal district court in Denver. The jury awarded nominal damages of $42,500 to 11 of 13 plaintiffs, but awarded no damages for any personal injury or health claims, other than requiring Cotter to perform periodic medical monitoring at minimal cost. The plaintiffs appealed the verdict to the Tenth Circuit Court of Appeals.

On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability incurred by Cotter as a result of these actions, as well as any liability arising in connection with the West Lake Landfill discussed in the next paragraph.

The United States Environmental Protection Agency (EPA) has advised Cotter that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. Cotter is alleged to have disposed of approximately 39,000 tons of soils mixed with 8,700 tons of leached barium sulfate at the site. Cotter, along with three other companies identified by the EPA as potentially responsible parties (PRPs), is reviewing a draft feasibility study that recommends capping the site. The PRPs are also engaged in discussions with the State of Missouri and the EPA. The estimated costs of remediation for the site are $10 to $15 million. Once a final feasibility study is complete and a remedy selected, it is expected that the PRPs will agree on an allocation of responsibility for the costs. Until an agreement is reached, Exelon Generation cannot predict its share of the costs.

In connection with the corporate restructuring, the responsibility to indemnify Cotter for any liability related to these matters was transferred to Exelon Generation. Management believes it has established an adequate contingent liability in connection with these proceedings.

Godley Park District Litigation. On April 18, 2001, the Godley Park District filed suit in Will County Circuit Court against ComEd and Exelon alleging that oil spills at Braidwood Station have contaminated the Park District's water supply. The complaint sought actual damages, punitive damages of $100 million and statutory penalties. The court dismissed all counts seeking punitive damages and statutory penalties, and the plaintiff has filed an amended complaint before the court. Exelon Generation is contesting the liability and damages sought by plaintiff.

Pennsylvania Real Estate Tax Appeals. Exelon Generation is involved in tax appeals regarding two of its nuclear facilities, Limerick (Montgomery County) and Peach Bottom (York County) and one of its fossil facilities, Eddystone (Delaware County), Exelon is also involved in the appeal for TMI (Dauphin County) through AmerGen. Exelon Generation does not believe the outcome of these matters will have a material adverse effect on Exelon Generation's results of operations or financial condition.

Enron. Exelon Generation is an unsecured creditor in Enron Corp.'s (Enron) bankruptcy proceeding. Exelon Generation's claim for power and other products sold to Enron in November and early December 2001 is $8.5 million. Enron may assert that Exelon Generation should not have closed

out and terminated all of its forward contracts with Enron. If Enron is successful in this argument, Exelon Generation's exposure could be greater than $8.5 million. Exelon Generation may also be subject to exposure due to the credit policies of ISO-operated spot markets that allocate defaults of market participants to non-defaulting participants. Exelon Generation has established an allowance for uncollectibles in anticipation of resolution of these matters.

General. Exelon Generation is involved in various other litigation matters. The ultimate outcome of such matters, while uncertain, is not expected to have a material adverse effect on Exelon Generation's financial condition or results of operations.

12. Fair Value of Financial Assets and Liabilities

The carrying amounts and fair values of Exelon Generation's financial assets and liabilities as of December 31 were as follows:

	2001	2000

	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Non-derivatives				
Assets:				
Cash and cash equivalents	$ 224	$ 224	$ 4	$ 4
Customer accounts receivable	316	316	316	316
Nuclear decommissioning trust funds	3,165	3,165	3,127	3,127
Liabilities:				
Long-term debt (including amounts due within one year)	1,025	1,040	209	209
Derivatives				
Energy Derivatives	92	92	(34)	(34)

As of December 31, 2001 and 2000, Exelon Generation's carrying amounts of cash and cash equivalents and accounts receivable are representative of fair value because of the short-term nature of these instruments. Fair values of the trust accounts for decommissioning nuclear plants and long-term debt are estimated based on quoted market prices for the same or similar issues. The fair value of Exelon Generation's and power purchase and sale contracts is determined using quoted exchange prices, external dealer prices, or internal valuation models which utilize assumptions of future energy prices and available market pricing curves. The fair value of Exelon Generation's energy derivatives is reported in the balance sheet as current or non-current assets or liabilities depending on the time until settlement of the transaction. At December 31, 2001, the following amounts were reported in Exelon Generation's consolidated balance sheet for the fair value of energy derivatives: accounts receivable of $109 million; other non-current assets of $62; accounts payable of $71; and non-current liabilities of $8.

Financial instruments that potentially subject Exelon Generation to concentrations of credit risk consist principally of cash equivalents, customer accounts receivable and energy derivatives. Exelon Generation places its cash equivalents with high-credit quality financial institutions. Generally, such investments are in excess of the Federal Deposit Insurance Corporation limits.

Exelon Generation utilizes derivatives to manage the utilization of its available generating capacity and provision of wholesale energy to its affiliates. Exelon Generation also utilizes energy option contracts and energy financial swap arrangements to limit the market price risk associated with forward energy commodity contracts. Additionally, Exelon Generation enters into certain energy-related derivatives for trading or speculative purposes. Exelon Generation would be exposed to credit-related losses in the event of non-performance by the counterparties that issued the derivative instruments. The credit exposure of derivatives contracts is represented by the fair value of contracts at the reporting date. The majority of power purchase and sale contracts are documented under master netting agreements.

On January 1, 2001, Exelon Generation recognized a non-cash gain of $12 million, net of income taxes, in earnings and deferred a non-cash gain of $5 million, net of income taxes, in accumulated other comprehensive income, a component of shareholders' equity, to reflect the initial adoption of SFAS No. 133, as amended. SFAS No. 133 must be applied to all derivative instruments and requires that such instruments be recorded in the balance sheet either as an asset or a liability measured at their fair value through earnings, with special accounting permitted for certain qualifying hedges.

During 2001, Exelon Generation recognized net gains of $16 million ($10 million, net of income taxes) relating to mark-to-market (MTM) adjustments of certain non-trading power purchase and sale contracts pursuant to SFAS No. 133. MTM adjustments on power purchase contracts are reported in fuel and purchased power and MTM adjustments on power sale contracts are reported as Operating Revenues in the Consolidated Statements of Income. During 2001, Exelon Generation recognized net gains aggregating $14 million ($10 million, net of income taxes) on derivative instruments entered into for trading purposes. Exelon Generation commenced financial trading in the second quarter of 2001. Gains and losses associated with financial trading are reported as either operating revenue or fuel and purchased power expense in the Consolidated Statements of Income. During 2001, no amounts were reclassified from accumulated other comprehensive income into earnings as a result of forecasted energy commodity transactions no longer being probable.

As of December 31, 2001, approximately $50 million of deferred net gains on derivative instruments accumulated in other comprehensive income are expected to be reclassified to earnings during the next twelve months. Amounts in accumulated other comprehensive income related to interest rate cash flows are reclassified into earnings when the forecasted interest payment occurs. Amounts in accumulated other comprehensive income related to energy commodity cash flows are reclassified into earnings when the forecasted purchase or sale of the energy commodity occurs. The majority of Exelon Generation's cash flow hedges are expected to settle within the next 3 years.

Exelon Generation classifies investments in the trust accounts for decommissioning nuclear plants as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized costs bases for the securities held in these trust accounts.

	December 31, 2001			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Equity securities	$ 1,666	$ 130	$ (236)	$ 1,560
Debt securities:				
Government obligations	882	28	(3)	907
Other debt securities	701	16	(19)	698
Total debt securities	1,583	44	(22)	1,605
Total available-for-sale securities	$ 3,249	$ 174	$ (258)	$ 3,165

	December 31, 2000			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
Equity securities	$ 1,712	$ 144	$ (180)	$ 1,676
Debt securities:				
Government obligations	940	40	—	980

Other debt securities	470	8	(7)	471
Total debt securities	1,410	48	(7)	1,451
Total available-for-sale securities	$ 3,122	$ 192	$ (187)	$ 3,127

Net unrealized losses of $84 million and net unrealized gains of $5 million, respectively, were recognized in Accumulated Depreciation and Other Comprehensive Income in Exelon Generation's Consolidated Balance Sheets at December 31, 2001 and 2000, respectively.

	For the years ended December 31,	
	2001	2000
Proceeds from sales	$ 1,624	$ 265
Gross realized gains	76	9
Gross realized losses	(189)	(46)

Net realized gains of $14 million and net realized losses of $37 million were recognized in Accumulated Depreciation in Exelon Generation's Consolidated Balance Sheets at December 31, 2001 and 2000, respectively, and $127 million of net realized losses was recognized in Other Income and Deductions in Exelon Generation's Consolidated Income Statements for 2001. The available-for-sale securities held at December 31, 2001 have an average maturity of eight to ten years.

13. Selected Quarterly Data (Unaudited)

The information shown below, in the opinion of management, includes all adjustments, consisting only of normal or recurring accruals, necessary to a fair presentation of such amounts. Due to the seasonal nature of the generation business, quarterly amounts vary significantly during the year.

	Calendar Quarter Ended							
	March 31,		June 30,		September 30,		December 31,	
	2001	2000	2001	2000	2001	2000	2001	2000
Revenues	$ 1,628	$ 510	$ 1,618	$ 645	$ 2,292	$ 941	$ 1,510	$ 1,178
Operating income	$ 268	$ 70	$ 113	$ 140	$ 225	$ 228	$ 266	$ 3
Income before cumulative effect of change in accounting principle	$ 158	$ 88	$ 71	$ 147	$ 167	$ 164	$ 116	($ 139)
Cumulative effect of a change in accounting principle	$ 12	—	—	—	—	—	—	—
Net income (loss)	$ 170	$ 88	$ 71	$ 147	$ 167	$ 164	$ 116	($ 139)

14. Related Party Transactions

Exelon Corporation

At December 31, 2000, Exelon Generation had a $696 million demand note payable, that was due no later than December 16, 2001, with Exelon related to the acquisition of Sithe, which was reflected in current liabilities in Exelon Generation's Consolidated Balance Sheet. Interest expense on the note payable was $23 million and $2 million for the years ended December 31, 2001 and 2000. The loan was repaid in full in June 2001.

Exelon Corporate Restructuring

At December 31, 2001, Exelon Generation had a long-term receivable of $291 million from ComEd resulting from the restructuring which is included in deferred debits and other assets, on Exelon Generation's consolidated balance sheet. This receivable represents ComEd's legal requirement to remit the recovery of decommissioning costs upon collection from the customers.

Exelon Business Service Company

Effective January 1, 2001, upon the corporate restructuring, Exelon Generation receives a variety of corporate support services from the Business Services Company (BSC), a subsidiary of Exelon, including executive management, legal, human resources, financial and information technology services. Such services are provided at cost including applicable overheads. Costs charged to Exelon Generation by BSC for the year ended December 31, 2001 were $78 million.

Power Purchase Agreements with ComEd and PECO

In connection with the restructuring transaction, ComEd and PECO entered into PPAs with Exelon Generation. Under the PPA between Exelon Generation and ComEd, Exelon Generation supplies all of ComEd's load requirements through 2004. Prices for energy vary depending upon the time of day and month of delivery, as specified in the PPA. During 2005 and 2006, ComEd will purchase energy and capacity from Exelon Generation, up to the available capacity of the nuclear

generation plants formerly owned by ComEd and transferred to Exelon Generation. Under the terms of the PPA with ComEd, Exelon Generation is responsible for obtaining the required transmission for its supply. The PPA with ComEd also specifies that prior to 2005, ComEd and Exelon Generation will jointly determine and agree on a market-based price for energy delivered under the PPA for 2005 and 2006. In the event that the parties cannot agree to market-based prices for 2005 and 2006 prior to July 1, 2004, ComEd has the option of terminating its PPA effective December 31, 2004.

Exelon Generation has also entered into a PPA with PECO whereby Exelon Generation will supply all of PECO's load requirements through 2010. Prices for energy are equivalent to the net proceeds from sales of unbundled generation to PECO's provider of last resort customers at rates PECO is allowed to charge customers who do not choose an alternate generation supplier. Under the terms of PPA, PECO is responsible for obtaining the required transmission for its supply.

Intercompany power purchases pursuant to the PPAs for the year ended December 31, 2001 for ComEd and PECO were $2.6 billion and $1.2 billion, respectively. Prior to the restructuring, Exelon Generation recorded revenues of $871 million and $798 million related to sales of energy to PECO for 2000 and 1999, respectively. During 2000, Exelon Generation recorded revenue of $403 million related to sales of energy to ComEd.

AmerGen

Exelon Generation has entered into a PPA dated November 22, 1999 with AmerGen. Under this PPA, Exelon Generation has agreed to purchase from AmerGen all of the residual energy from the Clinton Power Station through December 31, 2002. Currently, the residual output approximates 25% of the total output of the Clinton Power Station. For the years ended December 31, 2001 and 2000, the amount of purchased power recorded in Consolidated Statements of Income is $57 million and $52 million, respectively. As of December 31, 2001 and 2000, Exelon Generation had a payable of $3.1 million and $2.9 million, respectively, resulting from this PPA.

In addition, under a service agreement dated March 1, 1999, Exelon Generation provides AmerGen with certain operation and support services to the nuclear facilities owned by AmerGen. This service agreement has an indefinite term and may be terminated by Exelon Generation or by AmerGen on 90 days' notice. Exelon Generation is compensated for these services in an amount agreed to in the work order but not less than the higher of the fully allocated costs for performing the services or the market price. For the years ended December 31, 2001, 2000 and 1999, the amount charged to AmerGen for these services was $80 million, $32 million and $1 million respectively. As of December 31, 2001 and 2000, Exelon Generation had a receivable of $47 million and $20 million respectively resulting from these services.

In February 2002, Exelon Generation entered into an agreement to loan AmerGen up to $75 million at an interest rate of one-month LIBOR plus 2.25%. As of March 1, 2002, AmerGen had borrowed $30 million under this agreement. The loan is due November 1, 2002.

Sithe Energies, Inc.

In August 2001, Exelon Generation recorded a $150 million note receivable from Sithe. Sithe used the proceeds from the note to repay its subordinated debt. The note has a maturity date of August 20,

2004 and an interest rate of the Eurodollar rate, plus 2.25%. Sithe repaid this note in December 2001. For the year ended December 31, 2001, Exelon recorded $2.7 million of interest income on the note.

Beginning December 18, 2002, we will have the right to purchase all (but not less than all) of the remaining outstanding shares of the Sithe common stock. The option expires on December 18, 2005. In addition, each of Sithe's other stockholder groups will have the right to require us to purchase all (but not less than all) of its shares during the same period in which we can exercise our option. At the end of that period, if no stockholder has exercised its option, we will have a one-time option to purchase shares from the other stockholders to bring our holdings to 50.1% of the total outstanding shares. If we exercise our option or if all the stockholder groups exercise their put rights, the purchase price for 70% of the remaining 50.1% of the Sithe stock will be set at a fair market value plus a 10% premium in the case of a call or 10% discount in the case of a put, subject to a floor of $430 million and a ceiling of $650 million, and the remaining portion will be valued at fair market value subject to floor price of $141 million and a ceiling price of $330 million, plus, in each case, interest accrued from the beginning of the exercise period.

15. Change in Accounting Estimate

Effective April 1, 2001, Exelon Generation changed its accounting estimates related to the depreciation and decommissioning of certain generating stations. The estimated service lives were extended by 20 years for three nuclear stations, by periods of up to 20 years for certain fossil stations and by 50 years for a pumped storage station. Effective July 1, 2001, the estimated service lives were extended by 20 years for the remainder of Exelon Generation's operating nuclear stations. These changes were based on engineering and economic feasibility studies performed by Exelon Generation considering, among other things, future capital and maintenance expenditures at these plants. The extension of the estimated service lives for the nuclear generating facilities is subject to approval by the NRC. As a result of the change, depreciation and decommissioning expense for 2001 decreased $90 million ($54 million, net of income taxes). At the end of the year, annualized savings resulting from the change would be a decrease of $132 million ($79 million, net of income taxes).

16. Supplemental Financial Information

Supplemental Balance Sheet Information

	December 31, 2001	December 31, 2000
Valuation Allowances		
Allowance for Doubtful Accounts	$ 17	$ 2
Reserve for inventory obsolescence	$ 12	$ 79
Accumulated Amortization		
Nuclear Fuel	$ 1,838	$ 1,445

Supplemental Income Statement Information

	For the Years Ended December 31, 2001	2000	1999
Taxes Other than Income			
Real Estate	$ 94	$ 32	$ 18
Payroll	38	27	16
Other	17	5	3
Total	$ 149	$ 64	$ 37
Other, Net			
Investment Income	$ (8)	$ 14	—
Other		2	41

Total	$ (8)	$ 16	$ 41

Supplemental Cash Flow Information

	For the Years Ended December 31,		
	2001	2000	1999
Cash paid during the year:			
Interest (net of amount capitalized)	$ 74	$ 35	$ 18
Income taxes (net of refunds)	$ 335	—	—