PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-Q
July 30, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
(Mark One)
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2013
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

Indicate by check mark whether the registrants (1) have 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 registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes ý No ¨
Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

Public Service Enterprise Group Incorporated	
PSEG Power LLC	Large accelerated filer o Accelerated filer o Non-accelerated filer x Smaller reporting company o
Public Service Electric and Gas Company	Large accelerated filer o Accelerated filer o Non-accelerated filer x Smaller reporting company o

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý

As of July 16, 2013, Public Service Enterprise Group Incorporated had outstanding 505,857,262 shares of its sole class of Common Stock, without par value.

As of July 16, 2013, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and meet the conditions set forth in General Instruction H(1) (a) and (b) of Form 10-Q. Each is filing its Quarterly Report on Form 10-Q with the reduced disclosure format authorized by General Instruction H.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management’s beliefs as well as assumptions made by and information currently available to management. When used herein, the words “anticipate,” “intend,” “estimate,” “believe,” “expect,” “plan,” “should,” “hypothetical,” “potential,” “foreca variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1. Financial Statements—Note 9. Commitments and Contingent Liabilities, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC). These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and risks,
- any deterioration in our credit quality or the credit quality of our counterparties, including in our leveraged leases,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to sufficiently obtain coverage or recover proceeds of insurance on such matters,
- increases in competition in energy supply markets as well as competition for certain rate-based transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
- changes in technology and customer usage patterns.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
OPERATING REVENUES	$2,310	$2,098	$5,096	$4,973
OPERATING EXPENSES				
Energy Costs	755	761	1,910	1,940
Operation and Maintenance	646	629	1,356	1,257
Depreciation and Amortization	283	255	573	511
Taxes Other Than Income Taxes	14	20	35	49
Total Operating Expenses	1,698	1,665	3,874	3,757
OPERATING INCOME	612	433	1,222	1,216
Income from Equity Method Investments	3	2	5	2
Other Income	52	51	113	95
Other Deductions	(13)	(19)	(42)	(35)
Other-Than-Temporary Impairments	(2)	(7)	(4)	(12)
Interest Expense	(101)	(103)	(203)	(204)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	551	357	1,091	1,062
Income Tax Expense	(218)	(146)	(438)	(358)
NET INCOME	$333	$211	$653	$704
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):				
BASIC	505,900	505,903	505,921	505,956
DILUTED	507,381	506,969	507,301	506,999
EARNINGS PER SHARE:				
BASIC				
INCOME FROM CONTINUING OPERATIONS	$0.66	$0.42	$1.29	$1.39
NET INCOME	$0.66	$0.42	$1.29	$1.39
DILUTED				
INCOME FROM CONTINUING OPERATIONS	$0.66	$0.42	$1.29	$1.39
NET INCOME	$0.66	$0.42	$1.29	$1.39
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$0.3600	$0.3550	$0.7200	$0.7100

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See Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
NET INCOME	$333	$211	$653	$704
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $16, $17, $(11) and $(21) for the three and six months ended 2013 and 2012, respectively	(16)	(15)	11	22
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $0, $3, $0 and $(11) for the three and six months ended 2013 and 2012, respectively	—	(5)	—	15
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $1, $2, $3 and $17 for the three and six months ended 2013 and 2012, respectively	—	(5)	(4)	(25)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(7), $(6), $(14) and $(11) for the three and six months ended 2013 and 2012, respectively	9	8	19	15
Other Comprehensive Income (Loss), net of tax	(7)	(17)	26	27
COMPREHENSIVE INCOME	$326	$194	$679	$731

See Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$164	$379
Accounts Receivable, net of allowances of $61 and $56 in 2013 and 2012, respectively	1,133	1,069
Tax Receivable	226	227
Unbilled Revenues	257	314
Fuel	481	583
Materials and Supplies, net	435	422
Prepayments	312	283
Derivative Contracts	142	138
Deferred Income Taxes	32	49
Regulatory Assets	396	349
Other	37	56
Total Current Assets	3,615	3,869
PROPERTY, PLANT AND EQUIPMENT	28,515	27,402
Less: Accumulated Depreciation and Amortization	(7,954)	(7,666)
Net Property, Plant and Equipment	20,561	19,736
NONCURRENT ASSETS		
Regulatory Assets	3,628	3,830
Regulatory Assets of Variable Interest Entities (VIEs)	603	713
Long-Term Investments	1,323	1,324
Nuclear Decommissioning Trust (NDT) Fund	1,580	1,540
Other Special Funds	183	191
Goodwill	16	16
Other Intangibles	41	34
Derivative Contracts	161	153
Restricted Cash of VIEs	23	23
Other	325	296
Total Noncurrent Assets	7,883	8,120
TOTAL ASSETS	$32,059	$31,725

See Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$576	$1,026
Securitization Debt of VIEs Due Within One Year	232	226
Commercial Paper and Loans	157	263
Accounts Payable	1,046	1,304
Derivative Contracts	42	46
Accrued Interest	97	91
Accrued Taxes	31	17
Deferred Income Taxes	46	72
Clean Energy Program	204	153
Obligation to Return Cash Collateral	121	122
Regulatory Liabilities	120	67
Other	386	390
Total Current Liabilities	3,058	3,777
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	6,686	6,542
Regulatory Liabilities	215	209
Regulatory Liabilities of VIEs	11	10
Asset Retirement Obligations	644	627
Other Postretirement Benefit (OPEB) Costs	1,272	1,285
Accrued Pension Costs	717	876
Clean Energy Program	27	—
Environmental Costs	449	537
Derivative Contracts	158	122
Long-Term Accrued Taxes	167	164
Other	116	108
Total Noncurrent Liabilities	10,462	10,480
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,033	6,148
Securitization Debt of VIEs	385	496
Project Level, Non-Recourse Debt	24	43
Total Long-Term Debt	7,442	6,687
STOCKHOLDERS’ EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2013 and 2012—533,556,660 shares	4,842	4,833
Treasury Stock, at cost, 2013— 27,699,398 shares; 2012— 27,664,188 shares	(615)	(607)
Retained Earnings	7,231	6,942
Accumulated Other Comprehensive Loss	(362)	(388)

Total Common Stockholders' Equity	11,096	10,780
Noncontrolling Interest	1	1
Total Stockholders' Equity	11,097	10,781
Total Capitalization	18,539	17,468
TOTAL LIABILITIES AND CAPITALIZATION	$32,059	$31,725

See Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$653	$704
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	573	511
Amortization of Nuclear Fuel	95	84
Provision for Deferred Income Taxes (Other than Leases) and ITC	146	165
Non-Cash Employee Benefit Plan Costs	122	134
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(26)	(98)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	20	(86)
Deferred Storm Costs	(81)	5
Net Change in Other Regulatory Assets and Liabilities	62	(94)
Cost of Removal	(46)	(44)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(47)	(26)
Net Change in Certain Current Assets and Liabilities	24	278
Employee Benefit Plan Funding and Related Payments	(194)	(175)
Other	42	20
Net Cash Provided By (Used In) Operating Activities	1,343	1,378
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,406)	(1,280)
Proceeds from Sale of Capital Leases and Investments	42	1
Proceeds from Sales of Available-for-Sale Securities	681	850
Investments in Available-for-Sale Securities	(684)	(867)
Other	(12)	(43)
Net Cash Provided By (Used In) Investing Activities	(1,379)	(1,339)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(106)	16
Issuance of Long-Term Debt	900	500
Redemption of Long-Term Debt, including Securitization Debt	(556)	(240)
Cash Dividends Paid on Common Stock	(364)	(359)
Other	(53)	(25)
Net Cash Provided By (Used In) Financing Activities	(179)	(108)
Net Increase (Decrease) in Cash and Cash Equivalents	(215)	(69)
Cash and Cash Equivalents at Beginning of Period	379	834
Cash and Cash Equivalents at End of Period	$164	$765
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$138	$114
Interest Paid, Net of Amounts Capitalized	$194	$197
Accrued Property, Plant and Equipment Expenditures	$222	$207

See Notes to Condensed Consolidated Financial Statements.

PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
OPERATING REVENUES	$1,190	$985	$2,637	$2,546
OPERATING EXPENSES				
Energy Costs	496	447	1,356	1,269
Operation and Maintenance	280	284	562	525
Depreciation and Amortization	65	58	129	115
Total Operating Expenses	841	789	2,047	1,909
OPERATING INCOME	349	196	590	637
Other Income	35	37	82	67
Other Deductions	(10)	(17)	(38)	(32)
Other-Than-Temporary Impairments	(2)	(7)	(4)	(12)
Interest Expense	(29)	(32)	(59)	(62)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	343	177	571	598
Income Tax Expense	(139)	(73)	(230)	(241)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$204	$104	$341	$357

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
NET INCOME	$204	$104	$341	$357
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $16, $17, $(11) and $(22) for the three and six months ended 2013 and 2012, respectively	(14)	(15)	13	22
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $0, $3, $0 and $(11) for the three and six months ended 2013 and 2012, respectively	—	(5)	—	15
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $1, $2, $3 and $17 for the three and six months ended 2013 and 2012, respectively	(1)	(5)	(5)	(25)
Pension/OPEB adjustment, net of tax (expense) benefit of $(6), $(5), $(11) and $(10) for the three and six months ended 2013 and 2012, respectively	8	7	17	14
Other Comprehensive Income (Loss), net of tax	(7)	(18)	25	26
COMPREHENSIVE INCOME	$197	$86	$366	$383

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$4	$7
Accounts Receivable	279	269
Accounts Receivable—Affiliated Companies, net	145	340
Short-Term Loan to Affiliate	395	574
Fuel	481	583
Materials and Supplies, net	312	307
Derivative Contracts	106	118
Prepayments	12	17
Other	12	19
Total Current Assets	1,746	2,234
PROPERTY, PLANT AND EQUIPMENT	9,811	9,697
Less: Accumulated Depreciation and Amortization	(2,857)	(2,679)
Net Property, Plant and Equipment	6,954	7,018
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,580	1,540
Goodwill	16	16
Other Intangibles	42	34
Other Special Funds	38	36
Derivative Contracts	58	49
Other	136	105
Total Noncurrent Assets	1,870	1,780
TOTAL ASSETS	$10,570	$11,032

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2013	December 31, 2012
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$—	$300
Accounts Payable	384	498
Derivative Contracts	42	46
Deferred Income Taxes	4	16
Accrued Interest	27	26
Other	94	81
Total Current Liabilities	551	967
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,690	1,575
Asset Retirement Obligations	380	369
Other Postretirement Benefit (OPEB) Costs	227	221
Derivative Contracts	20	15
Accrued Pension Costs	228	272
Long-Term Accrued Taxes	39	50
Other	89	84
Total Noncurrent Liabilities	2,673	2,586
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
LONG-TERM DEBT		
Total Long-Term Debt	2,041	2,040
MEMBER'S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,566	4,725
Accumulated Other Comprehensive Loss	(303)	(328)
Total Member's Equity	5,305	5,439
TOTAL LIABILITIES AND MEMBER'S EQUITY	$10,570	$11,032

See disclosures regarding PSEG Power LLC included in the Notes to Condensed Consolidated Financial Statements.

PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30,	
	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$341	$357
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	129	115
Amortization of Nuclear Fuel	95	84
Provision for Deferred Income Taxes and ITC	74	184
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	20	(86)
Non-Cash Employee Benefit Plan Costs	33	34
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(47)	(26)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	97	94
Margin Deposit	(8)	36
Accounts Receivable	25	40
Accounts Payable	(77)	(14)
Accounts Receivable/Payable-Affiliated Companies, net	197	73
Other Current Assets and Liabilities	(8)	(6)
Employee Benefit Plan Funding and Related Payments	(44)	(39)
Other	27	6
Net Cash Provided By (Used In) Operating Activities	854	852
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(222)	(344)
Proceeds from Sales of Available-for-Sale Securities	625	677
Investments in Available-for-Sale Securities	(637)	(692)
Short-Term Loan—Affiliated Company, net	179	170
Net Cash Provided By (Used In) Investing Activities	(55)	(189)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(500)	(600)
Redemption of Long-Term Debt	(300)	(66)
Other	(2)	(7)
Net Cash Provided By (Used In) Financing Activities	(802)	(673)
Net Increase (Decrease) in Cash and Cash Equivalents	(3)	(10)
Cash and Cash Equivalents at Beginning of Period	7	12
Cash and Cash Equivalents at End of Period	$4	$2
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$60	$118
Interest Paid, Net of Amounts Capitalized	$56	$57
Accrued Property, Plant and Equipment Expenditures	$33	$49

See disclosures regarding PSEG Power LLC included in the Notes to the Condensed Consolidated Financial Statements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
OPERATING REVENUES	$1,423	$1,407	$3,418	$3,346
OPERATING EXPENSES				
Energy Costs	580	622	1,547	1,624
Operation and Maintenance	369	350	796	726
Depreciation and Amortization	207	188	422	378
Taxes Other Than Income Taxes	14	20	35	49
Total Operating Expenses	1,170	1,180	2,800	2,777
OPERATING INCOME	253	227	618	569
Other Income	15	12	28	23
Other Deductions	(1)	(1)	(2)	(2)
Interest Expense	(75)	(74)	(148)	(147)
INCOME BEFORE INCOME TAXES	192	164	496	443
Income Tax Expense	(71)	(63)	(196)	(145)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$121	$101	$300	$298

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
NET INCOME	$121	$101	$300	$298
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0, $0 and $1 for the three and six months ended 2013 and 2012, respectively	(1)	—	(1)	(1)
COMPREHENSIVE INCOME	$120	$101	$299	$297

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$19	$116
Accounts Receivable, net of allowances of $61 and $56 in 2013 and 2012, respectively	834	783
Accounts Receivable-Affiliated Companies, net	59	—
Unbilled Revenues	257	314
Materials and Supplies	120	114
Prepayments	221	29
Regulatory Assets	396	349
Derivative Contracts	21	5
Deferred Income Taxes	32	49
Other	17	24
Total Current Assets	1,976	1,783
PROPERTY, PLANT AND EQUIPMENT	18,015	17,006
Less: Accumulated Depreciation and Amortization	(4,851)	(4,726)
Net Property, Plant and Equipment	13,164	12,280
NONCURRENT ASSETS		
Regulatory Assets	3,628	3,830
Regulatory Assets of VIEs	603	713
Long-Term Investments	361	348
Other Special Funds	42	61
Derivative Contracts	76	62
Restricted Cash of VIEs	23	23
Other	121	123
Total Noncurrent Assets	4,854	5,160
TOTAL ASSETS	$19,994	$19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2013	December 31, 2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$575	$725
Securitization Debt of VIEs Due Within One Year	232	226
Commercial Paper and Loans	157	263
Accounts Payable	510	630
Accounts Payable—Affiliated Companies, net	—	73
Accrued Interest	70	65
Clean Energy Program	204	153
Deferred Income Taxes	47	60
Obligation to Return Cash Collateral	121	122
Regulatory Liabilities	120	67
Other	257	269
Total Current Liabilities	2,293	2,653
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,288	4,223
Other Postretirement Benefit (OPEB) Costs	990	1,011
Accrued Pension Costs	364	463
Regulatory Liabilities	215	209
Regulatory Liabilities of VIEs	11	10
Clean Energy Program	27	—
Environmental Costs	398	486
Asset Retirement Obligations	256	250
Derivative Contracts	138	107
Long-Term Accrued Taxes	43	32
Other	47	38
Total Noncurrent Liabilities	6,777	6,829
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 9)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	4,965	4,070
Securitization Debt of VIEs	385	496
Total Long-Term Debt	5,350	4,566
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2013 and 2012—132,450,344 shares	892	892
Contributed Capital	520	420
Basis Adjustment	986	986
Retained Earnings	3,175	2,875
Accumulated Other Comprehensive Income	1	2
Total Stockholder's Equity	5,574	5,175

Total Capitalization	10,924	9,741
TOTAL LIABILITIES AND CAPITALIZATION	$19,994	$19,223

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Six Months Ended June 30, 2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$300	$298
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	422	378
Provision for Deferred Income Taxes and ITC	75	75
Non-Cash Employee Benefit Plan Costs	78	89
Cost of Removal	(46)	(44)
Deferred Storm Costs	(81)	5
Net Change in Other Regulatory Assets and Liabilities	62	(94)
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	6	108
Materials and Supplies	(6)	(8)
Prepayments	(192)	(126)
Accounts Payable	47	(24)
Accounts Receivable/Payable-Affiliated Companies, net	(137)	(94)
Other Current Assets and Liabilities	8	13
Employee Benefit Plan Funding and Related Payments	(134)	(121)
Other	19	4
Net Cash Provided By (Used In) Operating Activities	421	459
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,148)	(870)
Proceeds from Sale of Available-for-Sale Securities	32	71
Investments in Available-for-Sale Securities	(13)	(71)
Solar Loan Investments	(15)	(48)
Restricted Funds	—	3
Net Cash Provided By (Used In) Investing Activities	(1,144)	(915)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(106)	16
Issuance of Long-Term Debt	900	500
Redemption of Long-Term Debt	(150)	(73)
Redemption of Securitization Debt	(106)	(101)
Contributed Capital	100	—
Other	(12)	(7)
Net Cash Provided By (Used In) Financing Activities	626	335
Net Increase (Decrease) In Cash and Cash Equivalents	(97)	(121)
Cash and Cash Equivalents at Beginning of Period	116	143
Cash and Cash Equivalents at End of Period	$19	$22
Supplemental Disclosure of Cash Flow Information:		

Income Taxes Paid (Received)	$110	$4
Interest Paid, Net of Amounts Capitalized	$135	$139
Accrued Property, Plant and Equipment Expenditures	$189	$158

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Condensed Consolidated Financial Statements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

This combined Form 10-Q is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G each is only responsible for information about itself and its subsidiaries.

Note 1. Organization and Basis of Presentation
Organization
PSEG is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG's four principal direct wholly owned subsidiaries are:

- Power—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy trading functions through three principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- PSE&G—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC. PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs, which are regulated by the BPU.
- PSEG Energy Holdings L.L.C. (Energy Holdings)—which primarily has investments in leases and solar generation projects through its direct wholly owned subsidiaries. Certain Energy Holdings' subsidiaries are subject to regulation by the FERC and the states in which they operate. Energy Holdings has also been awarded a contract to manage the transmission and distribution assets of the Long Island Power Authority (LIPA) starting in 2014.
- PSEG Services Corporation (Services)—which provides management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation
The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2012 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2013.
The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 18. Related-Party Transactions. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2012.

Note 2. Recent Accounting Standards
New Standards Adopted during 2013
Disclosures about Offsetting Assets and Liabilities
This accounting standard requires enhanced disclosures regarding assets and liabilities that are either offset in the financial statements, or are subject to an enforceable master netting arrangement or similar agreement. The guidance is applicable to certain financial instruments (e.g. derivatives) and securities borrowing and lending transactions. This

standard requires entities:

- to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on an entity's financial position, and

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

- to present both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities.

We adopted this standard retrospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 11. Financial Risk Management Activities.

Reclassification Adjustments out of Accumulated Other Comprehensive Income (AOCI)

This accounting standard requires entities to disclose the following information about reclassification adjustments related to AOCI:

- changes in AOCI balances by component; and
- significant amounts reclassified out of AOCI by respective line items of net income (for amounts that are required by GAAP to be reclassified to net income in their entirety in the same reporting period).

We adopted this standard prospectively effective January 1, 2013. As this standard requires disclosures only, it did not have any impact on our consolidated financial position, results of operations or cash flows. For additional information, see Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax.

New Accounting Standards Issued But Not Yet Adopted

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

This accounting standard was issued to address diversity in practice related to the presentation of an unrecognized tax benefit in certain cases. This standard requires entities to present an unrecognized tax benefit or a portion thereof on the Balance Sheet as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward.

However, in cases in which a net operating loss carryforward, a similar tax loss or a tax credit carryforward is not available at the reporting date under the tax law of the jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or the tax law of the jurisdiction does not require an entity to use, and the entity does not intend to use the deferred tax asset for such purpose, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets.

The standard is effective for fiscal years and interim periods beginning after December 15, 2013. We are currently analyzing the impact of this standard to our financial statements.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of these VIEs are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the Transition Funding and Transition Funding II assets are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II, respectively.

PSE&G’s maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of June 30, 2013 and December 31, 2012. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first six months of 2013 or in

2012. Further, PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 4. Asset Disposition

In June 2013, Energy Holdings closed on the sale of its investments in a commercial office complex for proceeds of $41 million, resulting in an after-tax gain of $6 million.

Note 5. Rate Filings

The following information discusses significant updates regarding orders and pending rate filings. This Note should be read in conjunction with Note 6. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2012.

- Weather Normalization Clause (WNC)—In April 2013, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2011-2012 Winter Period. As a result, provisional rates were approved to recover $41 million from customers during the 2012-2013 Winter Period, with a carryover deficiency of $24 million to the 2013-2014 Winter Period. In July 2013, PSE&G filed a petition with the BPU seeking approval to recover $26 million in revenues from its customers during the 2013-2014 Winter Period inclusive of the $24 million carryover deficiency.
- Solar and Energy Efficiency Recovery Charges (formerly RRC and currently Green Program Recovery Charges (GPRC))—In May 2013, the BPU approved PSE&G's 2012 request for an increase in GPRC to recover approximately $62 million in additional electric revenue and $8 million in additional gas revenue, on an annual basis. In June 2013, PSE&G filed a petition with the BPU requesting a decrease in GPRC of approximately $1 million in electric revenue and $1 million in gas revenue, on an annual basis for the six Green Programs.

Note 6. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding loans by class of customer, none of which are considered “non-performing.”

Credit Risk Profile Based on Payment Activity		
Consumer Loans	As of June 30, 2013	As of December 31, 2012
	Millions	
Commercial/Industrial	$188	$174
Residential	16	15
Total	$204	$189

Energy Holdings

Energy Holdings, through various of its indirect subsidiary companies, has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG’s Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings’ investments in the leases are comprised of the total expected lease receivables on its investments over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG’s Condensed Consolidated Balance

Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Condensed Consolidated Balance Sheets.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

The table below shows Energy Holdings' gross and net lease investment as of June 30, 2013 and December 31, 2012, respectively.

	As of June 30, 2013	As of December 31, 2012
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$705	$721
Estimated Residual Value of Leased Assets	529	535
	1,234	1,256
Unearned and Deferred Income	(409)	(416)
Gross Investments in Leases	825	840
Deferred Tax Liabilities	(687)	(723)
Net Investments in Leases	$138	$117

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties represent investments in lease receivables related to coal-fired assets and commercial real estate properties.

	Lease Receivables, Net of Non-Recourse Debt	
Counterparties' Credit Rating (Standard & Poor's (S&P))	As of	As of
As of June 30, 2013	June 30, 2013	December 31, 2012
	Millions	
AA	$20	$21
AA-	58	73
BBB+ - BBB-	316	316
B	166	166
Not Rated	145	145
Total	$705	$721

The "B" rating and the "Not Rated" above include lease receivables related to coal-fired assets in Pennsylvania and Illinois, respectively. As of June 30, 2013, the gross investment in the leases of such assets, net of non-recourse debt, was $561 million ($40 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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Asset	Location	Gross Investment	% Owned		Total	Fuel Type	Counter-parties' S&P Credit Ratings	Counterparty
		Millions			MW			
Powerton Station Units 5 and 6	IL	$134	64	%	1,538	Coal	Not Rated	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$84	64	%	1,044	Coal	Not Rated	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$116	17	%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$117	17	%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$110	100	%	603	Coal	B	GenOn REMA, LLC

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Indirect subsidiary companies of Energy Holdings lease three coal-fired generation facilities in Pennsylvania (Keystone, Conemaugh and Shawville) to GenOn REMA, LLC (GenOn REMA), a subsidiary of GenOn Energy Inc. (GenOn), which was acquired by NRG Energy, Inc. in December 2012. With respect to addressing various environmental controls: Keystone has installed a flue gas desulfurization (FGD) system for sulfur dioxide (SO_2), selective catalytic reduction (SCR) equipment for nitrogen oxide (NOx) and mercury control; Conemaugh has a FGD system, while SCR and mercury control equipment are scheduled to be installed and operational by the first quarter of 2015; and GenOn has disclosed its plan to place Shawville in a “long-term protective layup” by April 2015. GenOn has stated that it is evaluating whether to continue to pay the required rent and maintain the facility in accordance with the lease terms or terminate the lease for obsolescence in which case the lessee would be required, among other things, to pay the contractual termination value structured to recover Energy Holdings' indirect subsidiaries' lease investment as specified in the lease agreement.

Although all lease payments from the GenOn REMA leases are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

Nesbitt Asset Recovery, LLC (Nesbitt), (an indirect, wholly owned subsidiary of Energy Holdings), owns approximately 64% of the lease interest in the Powerton and Joliet coal units in Illinois, with the balance held by Associates Capital Investments, L.L.P. (Associates) (an affiliate of Citigroup, and, together with Nesbitt, the "Owner

Participants"). These facilities are leased to Midwest Generation (MWG), an indirect subsidiary of Edison Mission Energy (EME).

On December 17, 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. Immediately prior to that filing, EME, MWG and the Owner Participants, as well as certain affiliated owner lessors, entered into a forbearance agreement with holders of a majority of the lease debt that financed the original sale-leaseback transaction. The forbearance agreement, which was approved by the bankruptcy court, expired on April 5, 2013. In June 2013, the parties reached an agreement, which was approved by the Bankruptcy Court, to again extend the deadline for MWG to assume or reject the leases until September 30, 2013. As part of this settlement, (i) MWG will make partial lease payments of $4 million each month during the extension period starting in July 2013, (ii) the unpaid rent for the utilization of the facilities by MWG during pendency of the bankruptcy will be treated as an administrative expense in bankruptcy and (iii) the parties agree to not reject

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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the leases or foreclose on assets under lease during the extension period. Nesbitt is actively involved in the bankruptcy proceedings and continues to evaluate its options with respect to this lease.

MWG has substantially completed investments in mercury removal (Activated Carbon Injection) and NOx emission controls (low NOx burners and Selective Non-Catalytic Reduction systems), and plans to invest in SO_2 emission controls (Dry Sorbent Injection (Trona) systems). On April 4, 2013, MWG obtained approval from the Illinois Pollution Control Board to defer capital investments for up to two additional years to meet upcoming air emission compliance deadlines under Illinois law. Also, on July 8, 2013, the US Court of Appeals affirmed the judgment of the lower court dismissing claims brought by the U.S. Environmental Protection Agency (EPA) and the State of Illinois against EME and MWG for alleged violations of the Clean Air Act.

Note 7. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. The trust funds are managed by third-party investment advisers who operate under investment guidelines developed by Power.

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of June 30, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$636	$202	$(9)	$829
Debt Securities				
Government Obligations	388	5	(8)	385
Other Debt Securities	311	11	(4)	318
Total Debt Securities	699	16	(12)	703
Other Securities	48	—	—	48
Total NDT Available-for-Sale Securities	$1,383	$218	$(21)	$1,580

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$648	$147	$(6)	$789
Debt Securities				
Government Obligations	274	11	—	285
Other Debt Securities	320	22	—	342
Total Debt Securities	594	33	—	627
Other Securities	124	—	—	124
Total NDT Available-for-Sale Securities	$1,366	$180	$(6)	$1,540

These amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

	As of June 30, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$45	$18
Accounts Payable	$57	$53

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than and greater than 12 months.

	As of June 30, 2013				As of December 31, 2012			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$148	$(9)	$—	$—	$139	$(6)	$—	$—
Debt Securities								
Government Obligations (B)	208	(8)	1	—	34	—	1	—
Other Debt Securities (C)	146	(4)	2	—	31	—	6	—
Total Debt Securities	354	(12)	3	—	65	—	7	—
Other Securities	—	—	—	—	—	—	—	—
NDT Available-for-Sale Securities	$502	$(21)	$3	$—	$204	$(6)	$7	$—

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over a broad range of securities with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2013.

(B) Debt Securities (Government)—Unrealized losses on Power’s NDT investments in United States Treasury obligations and Federal Agency asset-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of June 30, 2013.

(C) Debt Securities (Corporate)—Power’s investments in corporate bonds are limited to investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2013.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	Millions			
Proceeds from NDT Fund Sales	$376	$290	$617	$635
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	23	26	60	42
Gross Realized Losses	(6)	(16)	(25)	(22)
Net Realized Gains (Losses) on NDT Fund	$17	$10	$35	$20

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in PSEG’s and Power’s Condensed Consolidated Statements of Operations. Net unrealized gains of $97 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power’s Condensed Consolidated Balance Sheet as of June 30, 2013.

The NDT available-for-sale debt securities held as of June 30, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$58
1 - 5 years	171
6 - 10 years	191
11 - 15 years	39
16 - 20 years	9
Over 20 years	235
Total NDT Available-for-Sale Debt Securities	$703

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2013, other-than-temporary impairments of $4 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor

trust commonly known as the “Rabbi Trust.”
PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

	As of June 30, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$14	$7	$—	$21
Debt Securities				
Government Obligations	110	1	(1)	110
Other Debt Securities	43	1	—	44
Total Debt Securities	153	2	(1)	154
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	$169	$9	$(1)	$177

Securities in the Rabbi Trust in a gross unrealized loss position have been in such position for less than twelve months.

	As of December 31, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$13	$5	$—	$18
Debt Securities				
Government Obligations	114	3	—	117
Other Debt Securities	45	2	—	47
Total Debt Securities	159	5	—	164
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	$175	$10	$—	$185

These amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Condensed Consolidated Balance Sheets as shown in the following table.

	As of June 30, 2013	As of December 31, 2012
	Millions	
Accounts Receivable	$4	$4
Accounts Payable	$3	$5

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

In March 2012, PSEG restructured the fixed income component of the Rabbi Trust. The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	Millions			
Proceeds from Rabbi Trust Sales	$47	$61	$64	$215
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$4	$1	$4	$6
Gross Realized Losses	(3)	—	(3)	—
Net Realized Gains (Losses) on Rabbi Trust	$1	$1	$1	$6

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Condensed Consolidated Statements of Operations. Net unrealized gains of $4 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of June 30, 2013. The Rabbi Trust available-for-sale debt securities held as of June 30, 2013 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$—
1 - 5 years	59
6 - 10 years	28
11 - 15 years	8
16 - 20 years	5
Over 20 years	54
Total Rabbi Trust Available-for-Sale Debt Securities	$154

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

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The fair value of assets in the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of June 30, 2013	As of December 31, 2012
	Millions	
Power	$38	$36
PSE&G	42	61
Other	97	88
Total Rabbi Trust Available-for-Sale Securities	$177	$185

Note 8. Pension and Other Postretirement Benefits (OPEB)

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis.
Pension and OPEB costs for PSEG are detailed as follows:

	Pension Benefits Three Months Ended June 30,		OPEB Three Months Ended June 30,		Pension Benefits Six Months Ended June 30,		OPEB Six Months Ended June 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
	Millions							
Components of Net Periodic Benefit Cost								
Service Cost	$29	$25	$5	$4	$58	$50	$10	$8
Interest Cost	53	55	16	16	107	111	32	32
Expected Return on Plan Assets	(87)	(77)	(5)	(5)	(174)	(153)	(10)	(9)
Amortization of Net Transition Obligation	—	—	—	—	—	—	—	1
Prior Service Cost (Credit)	(4)	(4)	(3)	(3)	(9)	(9)	(7)	(7)
Actuarial Loss	47	42	10	8	94	84	21	16
Net Periodic Benefit Cost	$38	$41	$23	$20	$76	$83	$46	$41
Effect of Regulatory Asset	—	—	—	5	—	—	—	10
Total Benefit Costs, Including Effect of Regulatory Asset	$38	$41	$23	$25	$76	$83	$46	$51

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Pension and OPEB costs for Power, PSE&G and PSEG's other subsidiaries are detailed as follows:

	Pension Benefits Three Months Ended		OPEB Three Months Ended		Pension Benefits Six Months Ended		OPEB Six Months Ended	
	June 30,		June 30,		June 30,		June 30,	
	2013	2012	2013	2012	2013	2012	2013	2012
	Millions							
Power	$11	$12	$5	$4	$22	$25	$11	$9
PSE&G	22	25	17	20	45	49	33	40
Other	5	4	1	1	9	9	2	2
Total Benefit Costs	$38	$41	$23	$25	$76	$83	$46	$51

During the three months ended March 31, 2013, PSEG contributed its entire planned contributions for the year 2013 of $145 million and $14 million into its pension and postretirement healthcare plans, respectively.

Note 9. Commitments and Contingent Liabilities
Guaranteed Obligations
Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.
Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.
In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.
Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.
In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The face value of Power's outstanding guarantees, current exposure and margin positions as of June 30, 2013 and December 31, 2012 are shown below:

	As of June 30, 2013	As of December 31, 2012
	Millions	
Face Value of Outstanding Guarantees	$1,569	$1,508
Exposure under Current Guarantees	$282	$226
Letters of Credit Margin Posted	$113	$124
Letters of Credit Margin Received	$38	$69
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$4	$15
Counterparty Cash Margin Received	$—	$(4)
Net Broker Balance Deposited (Received)	$41	$26
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that Could be Required	$679	$654
Liquidity Available under PSEG’s and Power’s Credit Facilities to Post Collateral	$3,541	$3,531
Additional Amounts Posted		
Other Letters of Credit	$46	$45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 11. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power’s credit rating to below investment grade, which would represent a three level downgrade from its current S&P's, Moody’s and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives. In 2012, the CFTC issued Final Rules regarding the definition of a swap dealer and the definition of a swap, and established reporting and record-keeping requirements for commercial end users including PSEG. In September 2012, a federal court vacated the CFTC's rule on monitoring of position limits for several commodities, including natural gas, thereby indefinitely delaying the effectiveness of these position limits rules. PSEG is carefully monitoring all of these new rules as they are issued to analyze the potential impact on its swap and derivatives transactions, including any potential increase in its collateral requirements.

In addition to amounts for outstanding guarantees, current exposure and margin positions, Power had posted letters of credit to support various other non-energy contractual and environmental obligations. See table above.

Environmental Matters

Passaic River

Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

The EPA has determined that an eight-mile stretch of the Passaic River in the area of Newark, New Jersey is a “facility” within the meaning of that term under CERCLA. The EPA has determined the need to perform a study of the entire 17-mile tidal reach of the lower Passaic River.

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PSE&G and certain of its predecessors conducted operations at properties in this area on or adjacent to the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites. When the Essex Site was transferred from PSE&G to Power, PSE&G obtained releases and indemnities for liabilities arising out of the former Essex generating station and Power assumed any environmental liabilities.

The EPA notified the potentially responsible parties (PRPs) that the cost of its Remedial Investigation and Feasibility Study (RI/FS) is now estimated at approximately $110 million. Seventy-three PRPs, including Power and PSE&G, agreed to assume responsibility for the RI/FS and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently seventy members, is presently executing the RI/FS. Approximately five percent of the RI/FS costs were attributable to PSE&G's former MGP sites and approximately one percent to Power's generating stations on an interim basis under the CPG's group agreement. Power has provided notice to insurers concerning this potential claim.

In 2007, the EPA released a draft “Focused Feasibility Study” (FFS) that proposed various options to address the contamination cleanup of the lower eight miles of the Passaic River. The EPA estimated costs for the proposed remedy range from $1.3 billion to $3.7 billion. The work contemplated by the FFS is not subject to the cost sharing agreement discussed above. The EPA's revised proposed FFS may be released for public comment as early as the fourth quarter of 2013.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. and Maxus Energy Corporation (Tierra/Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. Phase I of the removal work has been completed. Phase II is contingent on the approval of an appropriate sediment disposal facility. Tierra/Maxus have reserved their rights to seek contribution for the removal costs from the other PRPs, including Power and PSE&G.

The EPA has advised that the levels of contaminants at Passaic River mile 10.9 will require removal in advance of the completion of the RI/FS. The CPG members, with the exception of Tierra/Maxus, which are no longer members, have agreed to fund the removal, currently estimated at approximately $30 million. PSEG's share of that effort is approximately three percent.

Except for the Passaic River mile 10.9 removal, Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to the Passaic River matters.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit against a PRP (Occidental Chemical Corporation (OCC)) and its related companies in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of the PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed hazardous substances to a total of 11 sites or facilities that impacted these water bodies. In 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. Power and PSE&G filed answers to the complaints in 2010. On March 22, 2013, Power and PSE&G signed an agreement to settle the NJDEP vs. OCC litigation at a nominal cost. That settlement is contingent upon a public comment and NJDEP response period and the issuance of an order approving the settlement by the Court after conducting a fairness hearing. A stay of third-party discovery remains in place and has been extended. Power and PSE&G believe they have good and valid defenses to the allegations contained in the third party complaints and will vigorously assert those defenses should the matter not settle. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.

Natural Resource Damage Claims

In 2003, the NJDEP directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the United States Department of Commerce and the United States Department of the Interior sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSEG is unable to estimate its portion of the possible loss or range of loss related to this matter.

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Newark Bay Study Area
The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area and encouraged the PRPs to contact OCC to discuss participating in the RI/FS that OCC was conducting. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but it is uncertain at this time whether the PSEG companies will consent to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.
MGP Remediation Program
PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $491 million and $578 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $491 million as of June 30, 2013. Of this amount, $104 million was recorded in Other Current Liabilities and $387 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $491 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.
Prevention of Significant Deterioration (PSD)/New Source Review (NSR)
The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a “major modification,” as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.
In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.
Hazardous Air Pollutants Regulation
In accordance with a ruling of the U.S. Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation in February 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. Litigation of these matters remains pending and the impact on the implementation schedule is unknown at this time.

Power believes that it will not be necessary to install any additional material controls at its New Jersey facilities. Additional controls may be necessary at Power’s Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulations, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power’s jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the first quarter of 2015. Power's share of this investment is approximately $147 million.

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NOx Regulation

In April 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on Power’s generation fleet, as it imposes NO_x emissions limits that will require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 30, 2015. Retirement notifications for the combustion turbines, except for Salem Unit 3, have been filed with the PJM Interconnection, LLC (PJM). The Salem Unit 3 combustion turbine (38 MW) will be transitioning to an emergency generator. Evaluations are ongoing for the steam electric generation units.

Under current Connecticut regulations, Power’s Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NO_x emission limitations that were incorporated into the facilities’ operating permits. In 2010, Power negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System (NPDES) permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. Power prepared its renewal application in accordance with the FWPCA Section 316(b) and the 316(b) rules published in 2004.

As a result of several legal challenges to the 2004 316(b) rule by certain northeast states, environmentalists and industry groups, the rule has been suspended and has been returned to the EPA to be consistent with a 2009 United States Supreme Court decision which concluded that the EPA could rely upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations.

In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule by July 27, 2012. In April 2011, the EPA published a proposed rule to establish marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. In July 2012, the EPA and environmental groups agreed to delay the deadline to June 27, 2013 for finalization of the Rule. On June 27, 2013, the EPA and environmental groups agreed to further extend the deadline to November 4, 2013.

Power is unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on its future capital requirements, financial condition, results of operations or cash flows. The results of further proceedings on this matter could have a material impact on Power’s ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power’s once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in Power’s application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power’s share would have been approximately $575 million. These cost estimates have not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power’s forecasted capital expenditures.

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Capital Expenditures
The construction programs of PSEG and its subsidiaries are currently estimated to include a base level total investment of approximately $6.4 billion for the three years ended 2015. The three-year projected capital expenditures for PSEG, Power and PSE&G are as follows:

	2013	2014	2015
	Millions		
Power	$ 400	$ 365	$ 305
PSE&G	2,045	1,765	1,305
Other	95	40	30
Total PSEG	$ 2,540	$ 2,170	$ 1,640

Power's projected capital expenditures include baseline maintenance (investments to replace major parts and enhance operational performance), investments in response to environmental, regulatory or legal mandates and nuclear expansion. PSE&G's projections include material additions and replacements in its transmission and distribution systems to meet expected growth and manage reliability.
In May 2013, the BPU approved increased spending on renewable energy under PSE&G's Solar Loan and Solar 4 All investment programs (Solar Loan III and Solar 4 All Extension, respectively). PSE&G's projected expenditures through 2015 in the table above have been updated to include $215 million under its Solar Loan III and Solar 4 All Extension programs.
Power
During the six months ended June 30, 2013, Power made $171 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $51 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations.
PSE&G
During the six months ended June 30, 2013, PSE&G made $1,167 million of capital expenditures, including $1,148 million of investment in plant, primarily for reliability of transmission and distribution systems and $19 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $46 million, which is included in operating cash flows.
Energy Holdings
Included in Other for 2013 in the preceding table is a 19 MW solar project currently under construction in Arizona for which Energy Holdings had issued an outstanding guarantee of $20 million as of June 30, 2013.
Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)
PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU’s approval of the auction results. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G’s load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey’s renewable portfolio standards.
Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

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PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2010	2011	2012	2013	
36-Month Terms Ending	May 2013	May 2014	May 2015	May 2016	(A)
Load (MW)	2,800	2,800	2,900	2,800	
$ per kWh	0.09577	0.09430	0.08388	0.09218	

(A) Prices set in the 2013 BGS auction became effective on June 1, 2013 when the 2010 BGS auction agreements expired.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 18. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2017 to support its fossil generation stations and for supply of nuclear fuel for the Salem, Hope Creek and Peach Bottom nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2015 and a portion through 2017 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of June 30, 2013, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2017
	Millions
Nuclear Fuel	
Uranium	$470
Enrichment	$368
Fabrication	$137
Natural Gas	$953
Coal	$493

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Regulatory Proceedings

New Jersey Clean Energy Program

In June 2013, the BPU established the funding level for fiscal 2014 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2014 aggregate funding for all electric distribution companies (EDCs) is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a current liability of $204 million and a noncurrent liability of $27 million as of June 30, 2013 for its outstanding share of the fiscal 2014 and remaining fiscal 2013 funding. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

Long-Term Capacity Agreement Pilot Program (LCAPP)

In 2011, New Jersey enacted the LCAPP Act that resulted in the selection of three generators to build a total of approximately 2,000 MW of new combined-cycle generating facilities located in New Jersey. Each of the New Jersey EDCs, including PSE&G, was directed to execute a standard offer capacity agreement (SOCA) with the three selected generators, but did so under protest preserving their legal rights. The SOCA provides for the EDCs to guarantee specified annual capacity payments to the generators subject to the terms and conditions of the agreement. Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and this appeal is pending. In addition, the LCAPP Act itself has been challenged on constitutional grounds in federal court and that proceeding is ongoing. In July 2013, the SOCA contract with New Jersey Power Development LLC, a subsidiary of NRG Energy, Inc., was terminated early as a result of a default by the generator. The generator has accepted this early termination and this SOCA contract is no longer in effect. The other two SOCA contracts are currently in effect. SOCA contracts are for a 15-year term, which are scheduled to commence for one of the generators in the 2015/2016 delivery year and for the other generator in the 2016/2017 delivery year. These two contracts are for the aggregate notional amount of approximately 1,300 MWs of installed capacity. Based upon the expected percentage of state load that PSE&G will be serving during the term of these contracts, PSE&G would be responsible for the positive difference of the contract price and the annual RPM clearing price for approximately 52% or 676 MW of this amount provided that these generators satisfy their obligations under the SOCA, including the requirement that the specific generation units set forth in the contract achieve commercial operation.

The current estimated fair value of the SOCAs is recorded as a Derivative Asset or Liability with an offsetting Regulatory Asset or Liability on PSE&G's Consolidated Balance Sheets. See Note 12. Fair Value Measurements for additional information.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused damage to PSE&G's transmission and distribution system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure. Power incurred an additional $22 million and $50 million of storm-related expense for the three months and six months ended June 30, 2013, respectively, primarily for repairs at certain generating stations in Power's fossil fleet. Power had incurred $85 million of costs in 2012. These costs were recognized in Operation and Maintenance Expense, offset by $25 million and $19 million of insurance recoveries in 2013 and 2012, respectively. Power's current estimate of the total costs required to restore its damaged facilities to their pre-Superstorm Sandy condition, including costs already incurred, is approximately $364 million.

Leveraged Lease Investments

In January 2012, PSEG entered into a specific matter closing agreement with the IRS settling all matters related to cross border lease transactions. This agreement settled the leasing dispute with finality for all tax periods in which PSEG realized tax deductions from these transactions. In January 2012, PSEG also signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. In March 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements concluded ten years of audits for PSEG and the leasing issue for all tax years. For PSEG, the impact of these agreements was an increase in financial statement Income Tax Expense of approximately $175 million in the first quarter of 2012. In prior periods, PSEG had established financial statement tax liabilities for uncertain tax positions in the amount of $246 million with respect to these tax years. Accordingly, the settlement resulted in a net $71 million decrease in the first quarter of 2012 in the Income Tax Expense of PSEG.

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Cash Impact

For tax years 1997 through 2003, the tax and interest PSEG owes the IRS as a result of this settlement will be reduced by the $320 million PSEG has on deposit with the IRS for this matter. PSEG paid a net deficiency for these years of approximately $4 million during the second quarter of 2012. Based upon the closing agreement and the Form 870-AD for tax years 2004 through 2006, PSEG owes the IRS approximately $620 million in tax and interest. Based on the settlement of the leasing dispute, for tax years 2007 through 2010, the IRS owes PSEG approximately $676 million. PSEG has filed amended returns for tax years 2007-2010 reflecting the impact of the settlement. These returns have been audited by the IRS and accepted as filed. As required by statute, the IRS presented the refund claim to the Joint Committee on Taxation for approval. In October 2012, PSEG was notified that the Joint Committee took no exception to the refund claim. In April 2013, PSEG received confirmation from the IRS which shows that overpayments from the 2008 through 2010 tax years have been applied to satisfy the liabilities due with respect to tax years 2004 through 2007. Accordingly, no further cash payments will be required with respect to the contested leasing transactions. In addition to the above, PSEG will claim a tax deduction for the accrued deficiency interest associated with this settlement in 2012, which gives rise to a cash tax savings of approximately $100 million.

Note 10. Changes in Capitalization

The following capital transactions occurred in the six months ended June 30, 2013:

Power

- paid cash dividends of $500 million to PSEG, and
- paid $300 million of 2.50% Senior Notes at maturity.

PSE&G

- issued $500 million of 2.375% Secured Medium-Term Notes, Series I due May 2023,
- paid $150 million of 5.00% Secured Medium-Term Notes at maturity,
- issued $400 million of 3.80% Secured Medium-Term Notes, Series H due January 2043,
- received $100 million capital contribution from PSEG,
- paid $100 million of Transition Funding's securitization debt, and
- paid $6 million of Transition Funding II's securitization debt.

Note 11. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Commodity Prices

The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are marked to market (MTM) with changes in fair value recorded in the income statement. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

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Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and futures contracts to hedge

- forecasted energy sales from its generation stations and the related load obligations, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

Certain of these derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, subsequent to June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power’s de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of June 30, 2013 and December 31, 2012, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of June 30, 2013	As of December 31, 2012
	Millions	
Fair Value of Cash Flow Hedges	$1	$3
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$4	$9

The expiration date of the longest-dated cash flow hedge at Power is in 2014. Power’s after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the next 12 months are $4 million. There was no ineffectiveness associated with qualifying hedges as of June 30, 2013.

Trading Derivatives

The primary purpose of Power’s wholesale marketing operation is to optimize the value of the output of the generating facilities via various products and services available in the markets it serves. Historically, Power engaged in trading of electricity and energy-related products where such transactions were not associated with the output or fuel purchase requirements of its facilities. This trading consisted mostly of energy supply contracts where Power secured sales commitments with the intent to supply the energy services from purchases in the market rather than from its owned generation. Such trading activities were marked to market through the income statement and represented less than one percent of gross margin (revenues less energy costs) on an annual basis. Effective July 2011, Power discontinued trading activities and anticipates that it will not enter into any more trading derivative contracts.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. In addition, as further described in Note 9. Commitments and Contingent Liabilities, PSE&G was directed to execute long-term SOCAs with certain generators to support the LCAPP Act. These contracts qualify as derivatives and are marked to fair value with the offset recorded to Regulatory Assets and Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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Fair Value Hedges
PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of June 30, 2013, PSEG had seven interest rate swaps outstanding totaling $850 million. These swaps convert Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of June 30, 2013 and December 31, 2012, the fair value of all the underlying hedges was $42 million and $57 million, respectively.
Cash Flow Hedges
PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(1) million and $(2) million as of June 30, 2013 and December 31, 2012, respectively.
Fair Values of Derivative Instruments
The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. See Note 2. Recent Accounting Standards. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset in the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG. The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of June 30, 2013						
	Power (A)				PSE&G(A)	PSEG (A)	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts Millions	Non Hedges Energy-Related Contracts	Netting (B)	Total Power	Non Hedges Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
Derivative Contracts							
Current Assets	$1	$306	$(201)	$106	$21	$15	$142
Noncurrent Assets	—	99	(41)	58	76	27	161
Total Mark-to-Market Derivative Assets	$1	$405	$(242)	$164	$97	$42	$303
Derivative Contracts							
Current Liabilities	$—	$(243)	$201	$(42)	$—	$—	$(42)
Noncurrent Liabilities	—	(62)	42	(20)	(138)	—	(158)
Total Mark-to-Market Derivative (Liabilities)	$—	$(305)	$243	$(62)	$(138)	$—	$(200)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$1	$100	$1	$102	$(41)	$42	$103

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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	As of December 31, 2012						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts Millions	Non Hedges Energy-Related Contracts	Netting (B)	Total Power	Non Hedges Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
Derivative Contracts							
Current Assets	$3	$332	$(217)	$118	$5	$15	$138
Noncurrent Assets	—	75	(26)	49	62	42	153
Total Mark-to-Market Derivative Assets	$3	$407	$(243)	$167	$67	$57	$291
Derivative Contracts							
Current Liabilities	$—	$(265)	$219	$(46)	$—	$—	$(46)
Noncurrent Liabilities	—	(41)	26	(15)	(107)	—	(122)
Total Mark-to-Market Derivative (Liabilities)	$—	$(306)	$245	$(61)	$(107)	$—	$(168)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$3	$101	$2	$106	$(40)	$57	$123

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of June 30, 2013 and December 31, 2012. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the statement of financial position. As of June 30, 2013 and December 31, 2012, net cash collateral paid of $1 million and $2 million, respectively, were netted against the corresponding net derivative contract positions. Of the $1 million as of June 30, 2013, cash collateral of $1 million was netted against current liabilities. Of the $2 million as of December 31, 2012, cash collateral of $(3) million and $5 million were netted against current assets and current liabilities, respectively.

Certain of Power’s derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power’s credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on NYMEX and ICE that are fully collateralized) was $82 million and $98 million as of June 30, 2013 and December 31, 2012, respectively. As of June 30, 2013 and December 31, 2012, Power had the contractual right of offset of $46 million and $61 million, respectively, related to derivative instruments that are assets with the same counterparty under agreements and net of margin posted. If Power had been downgraded or lost its investment grade rating, it would have had additional collateral obligations of $36 million and $37 million as of June 30, 2013 and December 31, 2012, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $679 million and $654 million as of June 30, 2013 and December 31, 2012, respectively, discussed in Note 9. Commitments and Contingent Liabilities.

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended June 30, 2013 and 2012:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended June 30,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended June 30,		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended June 30,	
	2013	2012		2013	2012		2013	2012
	Millions							
PSEG (A)								
Energy-Related Contracts	$—	$(8)	Operating Revenues	$2	$13	Operating Revenues	$—	$1
Energy-Related Contracts	—	—	Energy Costs	—	(5)		—	—
Interest Rate Swaps	—	—	Interest Expense	(1)	(1)		—	—
Total PSEG	$—	$(8)		$1	$7		$—	$1
Power								
Energy-Related Contracts	$—	$(8)	Operating Revenues	$2	$13	Operating Revenues	$—	$1
Energy-Related Contracts	—	—	Energy Costs	—	(5)		—	—
Total Power	$—	$(8)		$2	$8		$—	$1

(A) Includes amounts for PSEG parent.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the six months ended June 30, 2013 and 2012:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Six Months Ended	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Six Months Ended	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Six Months Ended

	June 30, 2013	2012		June 30, 2013	2012		June 30, 2013	2012
	Millions							
PSEG (A)								
Energy-Related Contracts	$—	$30	Operating Revenues	$8	$52	Operating Revenues	$—	$—
Energy-Related Contracts	—	(4)	Energy Costs	—	(9)		—	—
Interest Rate Swaps	—	—	Interest Expense	(1)	(1)		—	—
Total PSEG	$—	$26		$7	$42		$—	$—
Power								
Energy-Related Contracts	$—	$30	Operating Revenues	$8	$52	Operating Revenues	$—	$—
Energy-Related Contracts	—	(4)	Energy Costs	—	(9)		—	—
Total Power	$—	$26		$8	$43		$—	$—

(A) Includes amounts for PSEG parent.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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The following reconciles the Accumulated Other Comprehensive Income for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2012	$12	$7
Less: Gain Reclassified into Income	(6)	(4)
Balance as of March 31, 2013	$6	$3
Less: Gain Reclassified into Income	(1)	—
Balance as of June 30, 2013	$5	$3

The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months and six months ended June 30, 2013 and 2012:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2013	2012	2013	2012
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$163	$40	$(46)	$235
Energy-Related Contracts	Energy Costs	(5)	3	53	(23)
Total PSEG and Power		$158	$43	$7	$212

Power’s derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $5 million for each of the three month periods and $10 million and $11 million for the six month periods ended June 30, 2013 and 2012, respectively.

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The following reflects the gross volume, on an absolute value basis, of derivatives as of June 30, 2013 and December 31, 2012:

Type	Notional Millions	Total	PSEG	Power	PSE&G
As of June 30, 2013					
Natural Gas	Dth	495	—	325	170
Electricity	MWh	233	—	233	—
Capacity	MW days	4	—	—	4
FTRs	MWh	30	—	30	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
Oils	Gallons	1	—	1	—
As of December 31, 2012					
Natural Gas	Dth	596	—	404	192
Electricity	MWh	208	—	208	—
Capacity	MW days	4	—	—	4
FTRs	MWh	19	—	19	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
Coal	Tons	1	—	1	—

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of June 30, 2013, 95% of the credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

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The following table provides information on Power's credit risk from others, net of cash collateral, as of June 30, 2013. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
	Millions				Millions	
Investment Grade—External Rating	$225	$36	$225	1	$114	(A)
Non-Investment Grade—External Rating	1	—	1	—	—	
Investment Grade—No External Rating	8	—	8	—	—	
Non-Investment Grade—No External Rating	11	—	11	—	—	
Total	$245	$36	$245	1	$114	

(A) Represents net exposure with PSE&G.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of June 30, 2013, Power had 176 active counterparties.

Note 12. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity's own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of June 30, 2013, these consist primarily of electric swaps whose basis is deemed significant to the fair value measurement, long-term electric load contracts, long-term gas supply and capacity contracts.

The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of June 30, 2013 and December 31, 2012, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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	Recurring Fair Value Measurements as of June 30, 2013				
Description	Total	Cash Collateral Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$261	$—	$—	$158	$103
Interest Rate Swaps (B)	$42	$—	$—	$42	$—
NDT Fund (C)					
Equity Securities	$829	$—	$829	$—	$—
Debt Securities—Govt Obligations	$385	$—	$—	$385	$—
Debt Securities—Other	$318	$—	$—	$318	$—
Other Securities	$48	$—	$—	$48	$—
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$21	$—	$21	$—	$—
Debt Securities—Govt Obligations	$110	$—	$—	$110	$—
Debt Securities—Other	$44	$—	$—	$44	$—
Other Securities	$2	$—	$—	$2	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(200)	$1	$—	$(63)	$(138)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$164	$—	$—	$158	$6
NDT Fund (C)					
Equity Securities	$829	$—	$829	$—	$—
Debt Securities—Govt Obligations	$385	$—	$—	$385	$—
Debt Securities—Other	$318	$—	$—	$318	$—
Other Securities	$48	$—	$—	$48	$—
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—
Debt Securities—Govt Obligations	$23	$—	$—	$23	$—
Debt Securities—Other	$10	$—	$—	$10	$—
Other Securities	$—	$—	$—	$—	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(62)	$1	$—	$(63)	$—
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$97	$—	$—	$—	$97

Rabbi Trust (C)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—
Debt Securities—Govt Obligations	$27	$—	$—	$27	$—
Debt Securities—Other	$10	$—	$—	$10	$—
Other Securities	$—	$—	$—	$—	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(138)	$—	$—	$—	$(138)

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Description	Recurring Fair Value Measurements as of December 31, 2012				
	Total	Cash Collateral Netting (D)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$234	$(3)	$—	$157	$80
Interest Rate Swaps (B)	$57	$—	$—	$57	$—
NDT Fund (C)					
Equity Securities	$789	$—	$789	$—	$—
Debt Securities—Govt Obligations	$285	$—	$—	$285	$—
Debt Securities—Other	$342	$—	$—	$342	$—
Other Securities	$124	$—	$—	$124	$—
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$18	$—	$18	$—	$—
Debt Securities—Govt Obligations	$117	$—	$—	$117	$—
Debt Securities—Other	$47	$—	$—	$47	$—
Other Securities	$3	$—	$—	$3	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(168)	$5	$—	$(62)	$(111)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$167	$(3)	$—	$157	$13
NDT Fund (C)					
Equity Securities	$789	$—	$789	$—	$—
Debt Securities—Govt Obligations	$285	$—	$—	$285	$—
Debt Securities—Other	$342	$—	$—	$342	$—
Other Securities	$124	$—	$—	$124	$—
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$3	$—	$3	$—	$—
Debt Securities—Govt Obligations	$23	$—	$—	$23	$—
Debt Securities—Other	$9	$—	$—	$9	$—
Other Securities	$1	$—	$—	$1	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(61)	$5	$—	$(62)	$(4)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (A)	$67	$—	$—	$—	$67

Rabbi Trust (C)					
Equity Securities—Mutual Funds	$6	$—	$6	$—	$—
Debt Securities—Govt Obligations	$39	$—	$—	$39	$—
Debt Securities—Other	$15	$—	$—	$15	$—
Other Securities	$1	$—	$—	$1	$—
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (A)	$(107)	$—	$—	$—	$(107)

(A) Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using the average of the bid/ask midpoints from multiple broker or dealer quotes or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.

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Level 3—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(B) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(C) The NDT Fund maintains investments in various equity and fixed income securities classified as "available for sale." The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as "available for sale." These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price (primarily Level 1). The Rabbi Trust equity index fund is valued based on quoted prices in an active market (Level 1).

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency asset-backed securities with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads (primarily Level 2). Short-term investments and certain commingled temporary investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2).

(D) Cash collateral netting represents collateral amounts netted against derivative assets and liabilities as permitted under the accounting guidance for Offsetting of Amounts Related to Certain Contracts.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group, and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

The following tables provide details surrounding significant Level 3 valuations as of June 30, 2013 and December 31, 2012. For Power, in general, electric swaps are valued based on at least two pricing inputs, basis and underlying. To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. Power's electric load contracts in which load consumption may change hourly are fair valued using certain unobservable inputs, such as historic load variability. For Power, long-term electric capacity contracts are measured using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, long-term gas supply contracts are measured at fair value using both actively traded pricing points as well as unobservable inputs such as gas prices beyond observable periods and long-term basis quotes and, accordingly, the fair value measurements are classified in Level 3. For PSE&G, long-term electric capacity contracts are measured at fair value using both observable capacity prices and unobservable inputs consisting of forecasts of future long-term electric capacity prices and include adjustments for contingencies, such as litigation risk and plant construction risk. Accordingly, the fair value measurements are classified as Level 3.

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Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of June 30, 2013		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
Power						
Electricity	Electric Swaps	$2	$3	Discounted cash flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Deals	1	(3)	Discounted cash flow	Historic Load Variability	-5% to +10%
Other	Various (A)	3	—			
Total Power		$6	$—			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$97	$(138)	Discounted cash flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		$97	$(138)			
TOTAL PSEG		$103	$(138)			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2012		Valuation Technique(s)	Significant Unobservable Input	Range
		Assets	(Liabilities)			
		Millions				
Power						
Electricity	Electric Swaps	$7	$(1)	Discounted cash flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	1	(2)	Discounted cash flow	Historic Load Variability	-5% to +10%
Other	Various (A)	5	(1)			
Total Power		$13	$(4)			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$67	$(107)	Discounted cash flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		$67	$(107)			
TOTAL PSEG		$80	$(111)			

(A) Includes long-term gas supply positions which are immaterial as of June 30, 2013 and December 31, 2012. Also includes long-term electric capacity positions which are immaterial as of December 31, 2012.

(B) Includes long-term gas supply and long-term electric capacity positions with various unobservable inputs. Significant unobservable inputs for the gas supply contracts include long-term basis prices in the range of $0 to $4/MMBTU of

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natural gas. Unobservable inputs for the long-term electric capacity contracts include forecasted capacity prices in the range of $100 to $400/MW day.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power and PSE&G are sellers, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value. For long-term electric capacity contracts where PSE&G is a buyer, an increase in the capacity price would increase the fair value.

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and six months ended June 30, 2013 and 2012, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended June 30, 2013

		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2013 Millions	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In/Out (D)	Balance as of June 30, 2013
PSEG Net Derivative Assets (Liabilities)	$(57)	$17	$ (1)	$—	$—	$6	$(35)
Power Net Derivative Assets (Liabilities)	$(17)	$17	$ —	$—	$—	$6	$6
PSE&G Net Derivative Assets (Liabilities)	$(40)	$—	$ (1)	$—	$—	$—	$(41)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Six Months Ended June 30, 2013

Description	Balance as of January 1, 2013	Total Gains or (Losses) Realized/Unrealized Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In/Out (D)	Balance as of June 30, 2013
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$(31)	$(17)	$ (1)	$—	$10	$4	$(35)
Power							
Net Derivative Assets (Liabilities)	$9	$(17)	$ —	$—	$10	$4	$6
PSE&G							
Net Derivative Assets (Liabilities)	$(40)	$—	$ (1)	$—	$—	$—	$(41)

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended June 30, 2012

Description	Balance as of April 1, 2012	Total Gains or (Losses) Realized/Unrealized Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In/Out (D)	Balance as of June 30, 2012
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$61	$7	$ (90)	$—	$(14)	$—	$(36)
Non-Recourse Debt	$(50)	$50	—	—	—	—	—
Power							
Net Derivative Assets (Liabilities)	$29	$7	$ —	$—	$(14)	$—	$22
PSE&G							
Net Derivative Assets	$32	$—	$ (90)	$—	$—	$—	$(58)

(Liabilities)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Six Months Ended June 30, 2012

Description	Balance as of January 1, 2012 Millions	Total Gains or (Losses) Realized/Unrealized Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances (Settlements) (C)	Transfers In/Out (D)	Balance as of June 30, 2012
PSEG							
Net Derivative Assets (Liabilities)	$21	$41	$ (55)	$—	$(43)	$—	$(36)
Non-Recourse Debt	$(50)	$50	$ —	$—	$—	$—	$—
Power							
Net Derivative Assets (Liabilities)	$24	$41	$ —	$—	$(43)	$—	$22
PSE&G							
Net Derivative Assets (Liabilities)	$(3)	$—	$ (55)	$—	$—	$—	$(58)

(A) PSEG’s and Power’s gains and losses attributable to changes in net derivative assets and liabilities include $17 million and $7 million in Operating Income in 2013 and 2012, respectively. Of the $17 million in Operating Income in 2013, $16 million is unrealized. Of the $7 million in Operating Income in 2012, $(7) million is unrealized. Energy Holdings' release from its obligation under the non-recourse debt is included in PSEG's Operating Income for 2012 and is offset by the write-off of the related assets.

(B) Mainly includes gains/losses on PSE&G’s derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G’s customers.

(C) Represents $(14) million in settlements for the three months ended June 30, 2012. Includes $10 million and $(43) million in settlements for the six months ended June 30, 2013 and 2012, respectively.

(D) During the three months ended June 30, 2013 and six months ended June 30, 2013, $6 million and $4 million, respectively, of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. The transfer was recognized as of the beginning of the first quarter (i.e. the quarter in which the transfer occurred), as per PSEG's policy. There were no transfers among levels during the three months ended June 30, 2012 and the six months ended June 30, 2012.

(E) PSEG’s and Power’s gains and losses attributable to changes in net derivative assets and liabilities include $(17) million and $41 million in Operating Income in 2013 and 2012, respectively. Of the $(17) million in Operating Income in 2013, $(8) million is unrealized. Of the $41 million in Operating Income in 2012, $(2) million is unrealized. Energy Holdings' release from its obligation under the non-recourse debt is included in PSEG's Operating Income for 2012 and is offset by the write-off of the related assets.

As of June 30, 2013, PSEG carried $1.9 billion of net assets that are measured at fair value on a recurring basis, of which $35 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.
As of June 30, 2012, PSEG carried $1.7 billion of net assets that are measured at fair value on a recurring basis, of which $36 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

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Fair Value of Debt
The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of June 30, 2013 and December 31, 2012.

	June 30, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$27	$42	$38	$57
Power -Recourse Debt (B)	2,041	2,361	2,340	2,818
PSE&G (B)	5,540	5,627	4,795	5,606
Transition Funding (PSE&G) (B)	590	643	690	765
Transition Funding II (PSE&G) (B)	27	28	32	34
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	25	25	44	44
Total Long-Term Debt	$8,250	$8,726	$7,939	$9,324

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. Carrying amount represents such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond’s future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 13. Other Income and Deductions

Other Income	Power Millions	PSE&G	Other (A)	Consolidated
Three Months Ended June 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$33	$—	$—	$33
Allowance of Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	5	—	5
Other	2	4	2	8
Total Other Income	$35	$15	$2	$52
Three Months Ended June 30, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$36	$—	$—	$36
Allowance of Funds Used During Construction	—	7	—	7
Solar Loan Interest	—	4	—	4
Other	1	1	2	4
Total Other Income	$37	$12	$2	$51
Six Months Ended June 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$80	$—	$—	$80
Allowance of Funds Used During Construction	—	12	—	12
Solar Loan Interest	—	11	—	11
Other	2	5	3	10
Total Other Income	$82	$28	$3	$113
Six Months Ended June 30, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$64	$—	$—	$64
Allowance of Funds Used During Construction	—	11	—	11
Solar Loan Interest	—	8	—	8
Other	3	4	5	12
Total Other Income	$67	$23	$5	$95

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Other Deductions	Power	PSE&G	Other (A)	Consolidated
	Millions			
Three Months Ended June 30, 2013				
NDT Fund Realized Losses and Expenses	$9	$—	$—	$9
Other	1	1	2	4
Total Other Deductions	$10	$1	$2	$13
Three Months Ended June 30, 2012				
NDT Fund Realized Losses and Expenses	$17	$—	$—	$17
Other	—	1	1	2
Total Other Deductions	$17	$1	$1	$19
Six Months Ended June 30, 2013				
NDT Fund Realized Losses and Expenses	$29	$—	$—	$29
Other	9	2	2	13
Total Other Deductions	$38	$2	$2	$42
Six Months Ended June 30, 2012				
NDT Fund Realized Losses and Expenses	$25	$—	$—	$25
Other	7	2	1	10
Total Other Deductions	$32	$2	$1	$35

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 14. Income Taxes

PSEG's, Power's and PSE&G's effective tax rates for the three months and six months ended June 30, 2013 and 2012 were as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
PSEG	39.6	%	40.9	%	40.1	%	33.7	%
Power	40.6	%	41.2	%	40.3	%	40.3	%
PSE&G	37.2	%	38.4	%	39.6	%	32.7	%

For the three months ended June 30, 2013, as compared to the same period in the prior year, PSEG's and PSE&G's effective tax rates were lower due primarily to depreciation flow-through.

For the six months ended June 30, 2013, PSEG's and PSE&G's effective tax rates were higher than last year's effective tax rates due primarily to a settlement in 2012 with the IRS in regard to leveraged leases and the federal tax audit for tax years 1997 through 2006.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 was eligible for 50% bonus depreciation for tax purposes. On January 2, 2013, the President signed into law the American Taxpayer Relief Act of

2012 that further extends the 50% bonus depreciation for qualified property placed into service before January 1, 2014. These provisions contain rules which afford certain projects which have a long production period, the benefit of bonus depreciation. These provisions have generated

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cash for PSEG through tax benefits related to the accelerated depreciation. These tax benefits would have otherwise been received over an estimated average 20 year period.

In June 2009, September 2008 and December 2007, PSEG made tax deposits with the IRS in the amounts of $140 million, $80 million and $100 million, respectively, to defray potential interest costs associated with disputed tax assessments associated with certain lease investments. On January 31, 2012, PSEG signed a specific matter closing agreement with the IRS regarding this matter. Based on this agreement, these deposits were applied against tax and interest due pursuant to the closing agreement. Further, on the same date, PSEG signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. In March 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements concluded ten years of audits for PSEG and the leasing issue for all tax years. The financial statement impacts of these agreements, net of existing financial statement reserves, was a net decrease in tax expense in the first quarter of 2012 of $71 million for PSEG, including $30 million and $1 million for PSE&G and Power, respectively.

Note 15. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	Derivative Contracts	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of March 31, 2013	$3	$(475)	$117	$(355)
Other Comprehensive Income before Reclassifications	—	—	(16)	(16)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	9	—	9
Net Current Period Other Comprehensive Income (Loss)	—	9	(16)	(7)
Balance as of June 30, 2013	$3	$(466)	$101	$(362)

Power	Other Comprehensive Income (Loss) Three Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	Derivative Contracts	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of March 31, 2013	$5	$(413)	$112	$(296)
Other Comprehensive Income before Reclassifications	—	—	(14)	(14)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	8	—	7
Net Current Period Other Comprehensive Income (Loss)	(1)	8	(14)	(7)
Balance as of June 30, 2013	$4	$(405)	$98	$(303)

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PSEG	Other Comprehensive Income (Loss) Six Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	Derivative Contracts	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2012	$7	$(485)	$90	$(388)
Other Comprehensive Income before Reclassifications	—	—	11	11
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(4)	19	—	15
Net Current Period Other Comprehensive Income (Loss)	(4)	19	11	26
Balance as of June 30, 2013	$3	$(466)	$101	$(362)

Power	Other Comprehensive Income (Loss) Six Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	Derivative Contracts	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2012	$9	$(422)	$85	$(328)
Other Comprehensive Income before Reclassifications	—	—	13	13
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(5)	17	—	12
Net Current Period Other Comprehensive Income (Loss)	(5)	17	13	25
Balance as of June 30, 2013	$4	$(405)	$98	$(303)

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2013			Six Months Ended June 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Derivative Contracts							
Gains (Losses) on Cash Flow Hedges	Operating Revenues	$2	$(1)	$1	$8	$(3)	$5
Interest Rate Swaps	Interest Expense	(1)	—	(1)	(1)	—	$(1)
Pension and OPEB Plans							
Amortization of Prior Service Cost (Credit)	Operation and Maintenance Expense	1	—	1	5	(2)	3
Amortization of Actuarial Loss	Operation and Maintenance Expense	(17)	7	(10)	(38)	16	(22)
Available-for-Sale Securities							
Realized Gains (Losses) on NDT Fund	Other Income	2	(1)	1	4	(2)	2
Other-Than-Temporary Impairments on NDT Fund	Other-Than-Temporary Impairments	(2)	1	(1)	(4)	2	(2)
Total		$(15)	$6	$(9)	$(26)	$11	$(15)

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended June 30, 2013			Six Months Ended June 30, 2013		
Description of Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	Location of Pre-Tax Amount In Statement of Operations	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount	Pre-Tax Amount	Tax (Expense) Benefit	After-Tax Amount
		Millions					
Derivative Contracts Gains (Losses) on Cash Flow Hedges	Operating Revenues	$2	$(1)	$1	$8	$(3)	$5
Pension and OPEB Plans							
Amortization of Prior Service Cost (Credit)	Operation and Maintenance Expense	2	(1)	1	4	(2)	2
Amortization of Actuarial Loss	Operation and Maintenance Expense	(16)	7	(9)	(32)	13	(19)
Available-for-Sale Securities							
Realized Gains (Losses) on NDT Fund	Other Income	2	(1)	1	4	(2)	2
Other-Than-Temporary Impairments on NDT Fund	Other-Than-Temporary Impairments	(2)	1	(1)	(4)	2	(2)
Total		$(12)	$5	$(7)	$(20)	$8	$(12)

	Balance as of December 31, 2011	Other Comprehensive Income (Loss) Six Months Ended June 30, 2012			Balance as of June 30, 2012
		Power	PSE&G	Other	
	Millions				
Derivative Contracts	$31	$(10)	$—	$—	$21
Pension and OPEB Plans	(438)	14	—	1	(423)
Available-for-Sale Securities	70	22	(1)	1	92
Accumulated Other Comprehensive Income (Loss)	$(337)	$26	$(1)	$2	$(310)

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Note 16. Earnings Per Share (EPS) and Dividends

Diluted EPS is 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 or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	$333	$333	$211	$211	$653	$653	$704	$704
EPS Denominator (Thousands)								
Weighted Average Common Shares Outstanding	505,900	505,900	505,903	505,903	505,921	505,921	505,956	505,956
Effect of Stock Based Compensation Awards	—	1,481	—	1,066	—	1,380	—	1,043
Total Shares	505,900	507,381	505,903	506,969	505,921	507,301	505,956	506,999
EPS								
Net Income	$0.66	$0.66	$0.42	$0.42	$1.29	$1.29	$1.39	$1.39

	Three Months Ended June 30,		Six Months Ended June 30,	
Dividend Payments on Common Stock	2013	2012	2013	2012
Per Share	$0.3600	$0.3550	$0.7200	$0.7100
in Millions	$182	$180	$364	$359

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 17. Financial Information by Business Segments

	Power	PSE&G	Energy Holdings	Other (A)	Consolidated
	Millions				
Three Months Ended June 30, 2013					
Total Operating Revenues	$1,190	$1,423	$18	$(321)	$2,310
Income (Loss) From Continuing Operations	204	121	4	4	333
Net Income (Loss)	204	121	4	4	333
Segment Earnings (Loss)	204	121	4	4	333
Gross Additions to Long-Lived Assets	79	576	21	6	682
Three Months Ended June 30, 2012					
Total Operating Revenues	$985	$1,407	$14	$(308)	$2,098
Income (Loss) From Continuing Operations	104	101	2	4	211
Net Income (Loss)	104	101	2	4	211
Segment Earnings (Loss)	104	101	2	4	211
Gross Additions to Long-Lived Assets	107	435	44	7	593
Six Months Ended June 30, 2013					
Total Operating Revenues	$2,637	$3,418	$34	$(993)	$5,096
Income (Loss) From Continuing Operations	341	300	4	8	653
Net Income (Loss)	341	300	4	8	653
Segment Earnings (Loss)	341	300	4	8	653
Gross Additions to Long-Lived Assets	222	1,148	27	9	1,406
Six Months Ended June 30, 2012					
Total Operating Revenues	$2,546	$3,346	$34	$(953)	$4,973
Income (Loss) From Continuing Operations	357	298	42	7	704
Net Income (Loss)	357	298	42	7	704
Segment Earnings (Loss)	357	298	42	7	704
Gross Additions to Long-Lived Assets	344	870	55	11	1,280
As of June 30, 2013					
Total Assets	$10,570	$19,994	$1,431	$64	$32,059
Investments in Equity Method Subsidiaries	$40	$—	$97	$—	$137
As of December 31, 2012					
Total Assets	$11,032	$19,223	$1,454	$16	$31,725
Investments in Equity Method Subsidiaries	$40	$—	$94	$—	$134

(A) Other activities include amounts applicable to PSEG (as parent company), Services and intercompany eliminations, primarily relating to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are priced in accordance with applicable regulations, including affiliate pricing rules, at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 18. Related-Party Transactions.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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Note 18. Related-Party Transactions
The following discussion relates to intercompany transactions, the majority of which are eliminated during the PSEG consolidation process in accordance with GAAP.
Power
The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
	Millions			
Revenue from Affiliates:				
Billings to PSE&G through BGSS (A)	$128	$112	$606	$563
Billings to PSE&G through BGS (A)	192	192	385	381
Total Revenue from Affiliates	$320	$304	$991	$944
Expense Billings from Affiliates:				
Administrative Billings from Services (B)	$(43)	$(38)	$(88)	$(72)
Total Expense Billings from Affiliates	$(43)	$(38)	$(88)	$(72)

Related-Party Transactions	As of June 30, 2013	As of December 31, 2012
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$107	$238
Receivables from PSE&G Related to Gas Supply Hedges for BGSS (A)	28	27
Receivable from (Payable to) Services (B)	(26)	(31)
Tax Receivable from (Payable to) PSEG (C)	23	111
Receivable from (Payable to) PSEG	13	(5)
Accounts Receivable (Payable)—Affiliated Companies, net	$145	$340
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	$395	$574
Working Capital Advances to Services (E)	$17	$17
Long-Term Accrued Taxes Receivable (Payable) (C)	$(39)	$(50)

PSE&G
The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
	Millions			
Expense Billings from Affiliates:				
Billings from Power through BGSS (A)	$(128)	$(112)	$(606)	$(563)
Billings from Power through BGS (A)	(192)	(192)	(385)	(381)
Administrative Billings from Services (B)	(62)	(57)	(123)	(107)
Total Expense Billings from Affiliates	$(382)	$(361)	$(1,114)	$(1,051)

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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Related-Party Transactions	As of June 30, 2013		As of December 31, 2012	
	Millions			
Payable to Power through BGS and BGSS Contracts (A)	$(107	)	$(238	)
Payable to Power Related to Gas Supply Hedges for BGSS (A)	(28	)	(27	)
Payable to Power for SREC Liability (F)	(9	)	(7	)
Receivable from (Payable to) Services (B)	(48	)	(65	)
Tax Receivable from (Payable to) PSEG (C)	244		256	
Receivable from (Payable to) PSEG	3		6	
Receivable from Energy Holdings	4		2	
Accounts Receivable (Payable)—Affiliated Companies, net	$59		$(73	)
Working Capital Advances to Services (E)	$33		$33	
Long-Term Accrued Taxes Receivable (Payable) (C)	$(43	)	$(32	)

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Condensed Consolidated Balance Sheets.

(F) Pursuant to a BPU Order, certain BGS suppliers will be reimbursed for the cost they incurred above $300 per Solar Renewable Energy Certificate (SREC) or per Solar Alternative Compliance Payment (SACP) during the period June 1, 2008 through May 31, 2010 and such excess cost will be passed on to ratepayers. In a December 2012 order, the BPU approved a Stipulation of Settlement (Stipulation) that described the mechanism by which BGS suppliers recover reasonable and prudently-incurred costs for these SRECs. In accordance with the Stipulation, New Jersey's EDCs, including PSE&G, made a Verification Filing defining the proposed BGS Supplier payments. PSE&G has estimated and accrued a total liability for the excess SREC cost expected to be recovered from ratepayers of $17 million as of June 30, 2013 and December 31, 2012, including approximately $9 million and $7 million for Power's share which is included in PSE&G's Accounts Receivable (Payable)—Affiliated Companies as of June 30, 2013 and December 31, 2012, respectively. Under current accounting guidance, Power was unable to record the related intercompany receivable on its Condensed Consolidated Balance Sheet, until the BPU issued an Order approving such payments. As a result, PSE&G's liability to Power was not eliminated in consolidation and is included in Other Current Liabilities on PSEG's Condensed Consolidated Balance Sheet as of June 30, 2013 and December 31, 2012. On May 29, 2013, the BPU issued an Order approving the additional BGS payment for these SRECs with a 45 day appeal period which expired in July 2013 with no appeals filed. As a result, Power recorded its $9 million receivable from PSE&G in July 2013.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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Note 19. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG Energy Resources & Trade LLC. The following table presents condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
Three Months Ended June 30, 2013					
Operating Revenues	$—	$1,535	$34	$(379)	$1,190
Operating Expenses	2	1,187	31	(379)	841
Operating Income (Loss)	(2)	348	3	—	349
Equity Earnings (Losses) of Subsidiaries	213	(2)	—	(211)	—
Other Income	10	35	—	(10)	35
Other Deductions	(2)	(9)	—	1	(10)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(26)	(6)	(6)	9	(29)
Income Tax Benefit (Expense)	11	(151)	1	—	(139)
Net Income (Loss)	$204	$213	$(2)	$(211)	$204
Comprehensive Income (Loss)	$197	$198	$—	$(198)	$197
Three Months Ended June 30, 2012					
Operating Revenues	$—	$1,329	$31	$(375)	$985
Operating Expenses	2	1,135	28	(376)	789
Operating Income (Loss)	(2)	194	3	1	196
Equity Earnings (Losses) of Subsidiaries	116	(1)	—	(115)	—
Other Income	11	39	—	(13)	37
Other Deductions	—	(17)	—	—	(17)
Other-Than-Temporary Impairments	—	(7)	—	—	(7)
Interest Expense	(31)	(10)	(4)	13	(32)
Income Tax Benefit (Expense)	10	(82)	—	(1)	(73)
Net Income (Loss)	$104	$116	$(1)	$(115)	$104
Comprehensive Income (Loss)	$86	$91	$(1)	$(90)	$86

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
Six Months Ended June 30, 2013					
Operating Revenues	$—	$3,338	$67	$(768)	$2,637
Operating Expenses	4	2,749	61	(767)	2,047
Operating Income (Loss)	(4)	589	6	(1)	590
Equity Earnings (Losses) of Subsidiaries	362	(2)	—	(360)	—
Other Income	19	83	—	(20)	82
Other Deductions	(10)	(29)	—	1	(38)
Other-Than-Temporary Impairments	—	(4)	—	—	(4)
Interest Expense	(53)	(16)	(10)	20	(59)
Income Tax Benefit (Expense)	27	(259)	2	—	(230)
Net Income (Loss)	$341	$362	$(2)	$(360)	$341
Comprehensive Income (Loss)	$366	$370	$—	$(370)	$366
Six Months Ended June 30, 2013					
Net Cash Provided By (Used In) Operating Activities	$386	$884	$3	$(419)	$854
Net Cash Provided By (Used In) Investing Activities	$152	$(411)	$—	$204	$(55)
Net Cash Provided By (Used In) Financing Activities	$(538)	$(476)	$(3)	$215	$(802)
Six Months Ended June 30, 2012					
Operating Revenues	$—	$3,202	$57	$(713)	$2,546
Operating Expenses	—	2,568	55	(714)	1,909
Operating Income (Loss)	—	634	2	1	637
Equity Earnings (Losses) of Subsidiaries	376	(4)	—	(372)	—
Other Income	24	70	—	(27)	67
Other Deductions	(7)	(25)	—	—	(32)
Other-Than-Temporary Impairments	—	(12)	—	—	(12)
Interest Expense	(60)	(20)	(8)	26	(62)
Income Tax Benefit (Expense)	24	(267)	2	—	(241)
Net Income (Loss)	$357	$376	$(4)	$(372)	$357
Comprehensive Income (Loss)	$383	$388	$(4)	$(384)	$383
Six Months Ended June 30, 2012					
Net Cash Provided By (Used In) Operating Activities	$301	$902	$3	$(354)	$852
Net Cash Provided By (Used In) Investing Activities	$365	$(601)	$(23)	$70	$(189)
Net Cash Provided By (Used In) Financing Activities	$(666)	$(310)	$19	$284	$(673)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
As of June 30, 2013					
Current Assets	$3,981	$8,288	$844	$(11,367)	$1,746
Property, Plant and Equipment, net	80	5,944	930	—	6,954
Investment in Subsidiaries	4,188	731	—	(4,919)	—
Noncurrent Assets	189	1,750	56	(125)	1,870
Total Assets	$8,438	$16,713	$1,830	$(16,411)	$10,570
Current Liabilities	$583	$10,443	$891	$(11,366)	$551
Noncurrent Liabilities	509	2,081	207	(124)	2,673
Long-Term Debt	2,041	—	—	—	2,041
Member's Equity	5,305	4,189	732	(4,921)	5,305
Total Liabilities and Member's Equity	$8,438	$16,713	$1,830	$(16,411)	$10,570
As of December 31, 2012					
Current Assets	$3,922	$8,084	$940	$(10,712)	$2,234
Property, Plant and Equipment, net	80	5,988	950	—	7,018
Investment in Subsidiaries	4,317	733	—	(5,050)	—
Noncurrent Assets	201	1,660	60	(141)	1,780
Total Assets	$8,520	$16,465	$1,950	$(15,903)	$11,032
Current Liabilities	$482	$10,187	$1,010	$(10,712)	$967
Noncurrent Liabilities	559	1,960	207	(140)	2,586
Long-Term Debt	2,040	—	—	—	2,040
Member's Equity	5,439	4,318	733	(5,051)	5,439
Total Liabilities and Member's Equity	$8,520	$16,465	$1,950	$(15,903)	$11,032

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of three reportable segments, which are:

- Power, our wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States,
- PSE&G, our public utility company which provides electric transmission services and distribution of electric energy and natural gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and
- Energy Holdings, which principally owns energy-related leveraged leases and solar generation projects.

Our business discussion in Part I, Item 1. Business of our 2012 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I Item 1A of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2012 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2013 and changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes, the 2012 Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2013.

OVERVIEW OF 2013 AND FUTURE OUTLOOK

Our business plan is designed to maintain earnings stability while achieving growth in recognition of market, regulatory and economic trends. We continue to focus on operational excellence to provide the foundation for our financial strength, which enables us to invest in a disciplined way.

Our financial results for the first six months of 2013 were lower when compared to the first half of 2012. In the power markets in which our generation fleet operates, natural gas prices have a major impact on the price that generators receive for their output. While wholesale natural gas prices during the period remained low relative to historic prices following multiple years of steep declines, financial results for our generation operations were favorably impacted by increased output and higher market prices driven by colder winter weather in the period as compared to the first six months in 2012, as well as cost controls, partially offset by mark-to market losses in 2013 due to the impact of rising prices on our forward sale positions.

Under the PJM capacity auction conducted in May 2013, Power cleared 8,637 MW of its generating capacity at an average price of $166 per MW-day for the 2016-2017 delivery period. While this year's auction resulted in lower clearing prices for the PJM Regional Transmission Organization (RTO), Power benefited from higher prices than the rest of the RTO, as the majority of its generation fleet is situated in the relatively constrained Eastern part of PJM. For a more detailed discussed on the RPM capacity auction, refer to Part II. Item 5. Other Information—Federal Regulation—Capacity Market Issues.

Our utility business benefited from increased transmission investment during the first half of the year, but financial results were impacted by the absence of last year's tax settlement. In the first six months of 2013, we continued to invest capital in transmission and distribution infrastructure projects, aimed at maintaining the reliability of our service to our customers. Over the past few years, these types of investments have altered the business mix of our results of operations to reflect a higher percentage contribution by our regulated utility.

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we monitor significant regulatory and legislative developments. Competitive wholesale power market design is of particular importance to our results and we continue to advocate for policies and rules that promote competitive electricity markets. This includes opposing efforts to subsidize generation and procurement activities in New Jersey in connection with the Long-Term Capacity Agreement Pilot Program (LCAPP) and in Maryland through the Maryland Public Service Commission Request for Proposal and supporting rule changes which we believe are necessary to avoid artificial price suppression and other distortions in the energy and capacity markets.

We continued to monitor and advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA). In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. Clean Air Act regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology (MACT) rules are also of significance; however, we believe our generation business remains well-positioned for such regulations if and when they are implemented.
As discussed in further detail under Part II. Item 5. Other Information—Federal Regulation—Transmission Regulation—Transmission Policy Developments, the FERC's rules under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are challenging the FERC's determination in court as we do not believe that the FERC sufficiently justified its decision to alter this right embedded in the FERC-approved contracts and tariffs. At the same time, the FERC's action presents opportunities for us to construct transmission outside of our service territory.
At year-end 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. The New Jersey Board of Public Utilities (BPU) issued an order allowing us to defer actually incurred prudent otherwise unreimbursed, incremental, storm restoration costs not otherwise recoverable through base rates or insurance. In February 2013, the BPU announced that it would initiate a generic proceeding to evaluate the prudency of extraordinary, storm-related costs incurred by all of the regulated utilities as a result of the natural disasters experienced in New Jersey in 2011 and 2012. In June 2013, we made a compliance filing with the BPU providing the details of our storm restoration costs for Superstorm Sandy as well as other major storms and seeking to demonstrate that we responded to these extreme weather events in a timely, diligent and thorough manner and that the costs incurred were prudent. We requested that the BPU issue an Order approving the compliance filing and specifically finding that the storm costs incurred were reasonable and prudent, and should be recovered from ratepayers.
As discussed further in Note 9. Commitments and Contingent Liabilities, in the first six months of 2013, Power incurred significant storm-related expenses, primarily for repair at certain of its coal and gas-fired generating stations. We are seeking recovery from our insurers for the property damage, above our self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. In June 2013, we filed suit against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. For a more detailed discussion concerning this proceeding, refer to Part II Item 1. Legal Proceedings—Superstorm Sandy.
On February 20, 2013, we filed a petition with the BPU describing our Energy Strong program, consisting of $3.9 billion of proposed improvements we recommend making to our gas and electric distribution systems over a ten year period to harden and improve resiliency. In the petition, we sought approval for $2.6 billion of the $3.9 billion of investments over an initial five year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. We cannot predict the outcome of this pending proceeding, including whether the program will be approved or the terms under which it would be approved. We anticipate seeking BPU approval to complete our investment under the program at a later date. In addition, we anticipate investing an additional $1.5 billion in our transmission system for the same reason. As proposed, we believe that the rate impacts of the Energy Strong program will be significantly muted as a result of scheduled reductions to customer bills that will be taking place over the next few years and assuming continued low gas prices. See Part II Item 5. Other Information—State Regulation—Energy Strong Program for additional details.
We continue to take all necessary steps in connection with the expected January 1, 2014 commencement of our management of the Long Island Power Authority (LIPA) transmission and distribution (T&D) system. Legislation enacted in New York in July 2013 would enable us to have an expanded role in management of LIPA's T&D system. A proposed revised contract with LIPA is currently under negotiation. See Part II Item 5. Other Information—Business Operations and Strategy—Energy Holdings—Products and Services for additional details.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented in the first half of the year as we remain diligent in managing costs. In the first six months of 2013, our

- outstanding performance allowed us to increase generation to meet loads, and
- construction of transmission and solar projects proceeded on schedule and within budget.

Financial Strength

Our financial position remained strong during the first six months of 2013 as we:

- had cash on hand of $164 million as of June 30, 2013,
- extended the expiration date of approximately half of our credit facilities, and maintained substantial liquidity and solid investment grade credit ratings, as evidenced by the recent credit rating upgrades by Standard & Poor's (S&P) of PSEG, Power and PSE&G as disclosed below in Liquidity and Capital Resources—Credit Ratings,
- completed pension and other postretirement benefit funding for 2013,
- refinanced PSE&G maturing debt at historically low rates and repaid Power's maturing debt with cash on hand, and
- increased our indicated annual dividend to $1.44.

We expect to be able to fund our proposed Energy Strong program with internally generated cash and external debt financing.

Disciplined Investment

We seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In addition to the proposed Energy Strong program discussed above, in the first six months of 2013 we

- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs,
- obtained approval from the BPU to increase our spending up to $247 million and $199 million under our Solar 4 All Extension and Solar Loan III investment programs, respectively (see Part II. Item 5. Other Information—State Regulation for further detail), and
- continued construction of a 19 MW solar project in Arizona.

Delays in the construction schedules of our projects could impact their costs as well as the timing of expected revenues.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and FERC of market design rules that continue to protect competition and achieve appropriate Reliability Pricing Model (RPM) and BGS pricing, and
- engage multiple stakeholders, including regulators, government officials, customers and investors.

For the remainder of 2013 and beyond, the key issues and challenges we expect our business to confront include

- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- uncertainty in the national and regional economic recovery and continuing customer conservation efforts, which impact customer demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, as well as cost recovery and opportunities for investment in system strengthening, including our proposed Energy Strong program,
- financially-stressed power plant leveraged lease investments,
- delays and other obstacles that might arise in connection with the construction of our transmission and distribution projects, including in connection with permitting and regulatory approvals, and
- the successful transition to our management of the LIPA transmission and distribution system. See Part II Item 5. Other Information—Business Operations and Strategy—Products and Services for additional details.

RESULTS OF OPERATIONS

The results for PSEG, PSE&G, Power and Energy Holdings for the three months and six months ended June 30, 2013 and 2012 are presented below:

	Three Months Ended June 30,		Six Months Ended June 30,	
Earnings (Losses)	2013	2012	2013	2012
	Millions			
Power	$204	$104	$341	$357
PSE&G	121	101	300	298
Energy Holdings	4	2	4	42
Other (A)	4	4	8	7
PSEG Net Income	$333	$211	$653	$704

	Three Months Ended June 30,		Six Months Ended June 30,	
Earnings Per Share (Diluted)	2013	2012	2013	2012
PSEG Net Income	$0.66	$0.42	$1.29	$1.39

(A) Other primarily includes parent company interest and financing activity and certain administrative and general expenses.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. This includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions. This also includes impairments on certain NDT securities which are included in Other-Than-Temporary Impairments and the interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO), which is recorded in Operation and Maintenance Expense and the depreciation related to the ARO asset.

Our results also include the after-tax impacts of non-trading mark-to-market (MTM) activity, which consist of the financial impact from positions with forward delivery dates.

The variances in our Net Income include the changes related to NDT and MTM shown in the chart below:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	Millions, after tax			
NDT Fund Income (Expense)	$8	$4	$17	$9
Non-Trading MTM Gains (Losses)	$80	$(10)	$(25)	$42

Our $122 million increase in Net Income for the three months ended June 30, 2013 was driven primarily by

- an increase in net MTM gains in 2013 resulting from a decrease in prices on forward positions, and
- higher revenues due to increased investments in transmission projects.

Our $51 million decrease in Net Income for the six months ended June 30, 2013 was driven primarily by

- lower average pricing and lower volumes of electricity sold under the BGS contracts and wholesale load contracts at Power,
- higher gas costs related to our BGSS contractual obligations and higher generation fuel costs,

- higher MTM losses due to an increase in prices on forward prices in PJM,

- higher Operation and Maintenance Costs, including repairs related to damage caused by Superstorm Sandy, and
- higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 Internal Revenue Service (IRS) audits in 2012.

The decreases were partially offset by

- higher capacity revenues and operating reserve revenues in PJM, and
- higher revenues due to increased investments in transmission projects.

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding charges related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Note 18. Related-Party Transactions. For an explanation of the variances, see the discussions for Power, PSE&G and Energy Holdings that follow the table below:

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$2,310	$2,098	$212	10	$5,096	$4,973	$123	2
Energy Costs	755	761	(6)	(1)	1,910	1,940	(30)	(2)
Operation and Maintenance	646	629	17	3	1,356	1,257	99	8
Depreciation and Amortization	283	255	28	11	573	511	62	12
Taxes Other than Income Taxes	14	20	(6)	(30)	35	49	(14)	(29)
Income from Equity Method Investments	3	2	1	50	5	2	3	N/A
Other Income and (Deductions)	39	32	7	22	71	60	11	18
Other-Than-Temporary Impairments	2	7	(5)	(71)	4	12	(8)	(67)
Interest Expense	101	103	(2)	(2)	203	204	(1)	—
Income Tax Expense	218	146	72	49	438	358	80	22

Power

	Three Months Ended June 30,		Increase/ (Decrease)	Six Months Ended June 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$204	$104	$100	$341	$357	$(16)

For the three months ended June 30, 2013, the primary reason for the $100 million increase in Net Income was net MTM gains in 2013 resulting from a decrease in prices on forward positions as well as higher capacity payments, partially offset by lower generation prices and volumes.

For the six months ended June 30, 2013, the primary reasons for the $16 million decrease in Net Income were:

- lower average pricing and lower volumes of electricity sold under our BGS contracts,
- lower volumes on wholesale load contracts in the PJM and New England regions,
- lower net revenues due to MTM losses in 2013 due to an increase in prices on forward positions in the PJM region,
- higher gas costs related to obligations under the BGSS contract and higher generation costs due to higher fuel costs, and
- higher Operation and Maintenance Costs in 2013, including costs related to damage caused by Superstorm Sandy at our fossil plants,

These decreases were partially offset by

- higher capacity revenues resulting from higher auction prices and an increase in operating reserve revenue in PJM, and
- higher sales volumes and gas prices under the BGSS contract due to colder average temperatures in 2013.

The quarter and year-to date details for these variances are discussed below:

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$1,190	$985	$205	21	$2,637	$2,546	$91	4
Energy Costs	496	447	49	11	1,356	1,269	87	7
Operation and Maintenance	280	284	(4)	(1)	562	525	37	7
Depreciation and Amortization	65	58	7	12	129	115	14	12
Other Income (Deductions)	25	20	5	25	44	35	9	26
Other-Than-Temporary Impairments	2	7	(5)	(71)	4	12	(8)	(67)
Interest Expense	29	32	(3)	(9)	59	62	(3)	(5)
Income Tax Expense	139	73	66	90	230	241	(11)	(5)

Three Months Ended June 30, 2013 As Compared to 2012

Operating Revenues increased $205 million due to changes in generation and gas supply revenues.

Generation Revenues increased $182 million due primarily to

- a net increase of $181 million due primarily to MTM gains in 2013 in the PJM and New York regions resulting from a change in prices on forward positions, and
- a net increase of $63 million due to higher capacity and other revenues, of which $54 million resulted from higher auction prices and $9 million from an increase in operating reserves in the PJM region,
- partially offset by a decrease of $37 million due to lower average pricing and lower volumes of electricity sold under our BGS contracts, and
- a decrease of $25 million due primarily to lower volumes on wholesale load contracts in the PJM and New England regions.

Gas Supply Revenues increased $23 million due primarily to

- a net increase of $15 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during 2013 at higher average gas prices, and
- an increase of $8 million due to higher average prices from sales to third party customers, partially offset by lower volumes.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $49 million due to

- Generation costs increased $32 million due primarily to $64 million of higher fuel costs reflecting higher average realized natural gas prices and higher nuclear fuel prices and MTM losses resulting from lower prices on forward positions in 2013. This increase was partially offset by $16 million of lower load contract volumes in 2013 and $16 million related to lower congestion costs in the PJM region.
- Gas costs increased $17 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due primarily to colder average temperatures in 2013 and higher average prices on third-party sales, partially offset by lower volumes.

Operation and Maintenance decreased $4 million due primarily to the recognition of a $25 million insurance recovery related to Superstorm Sandy, partially offset by $22 million in incremental costs associated with Superstorm Sandy.

Depreciation and Amortization increased $7 million due primarily to a higher depreciable asset base, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012 and completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012.

Other Income and (Deductions) increased $5 million due primarily to higher net earnings from the NDT Fund in 2013.

Other-Than-Temporary Impairments decreased $5 million due primarily to a decrease in impairments on the NDT Fund in 2013.

Interest Expense decreased $3 million due primarily to a decrease from lower outstanding debt in 2013 resulting from certain debt redeemed prior to maturity in 2012, partially offset by higher interest costs in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense increased $66 million in 2013 due primarily to higher pre-tax income.

Six Months Ended June 30, 2013 As Compared to 2012

Operating Revenues increased $91 million due to changes in generation and gas supply revenues.

Gas Supply Revenues increased $94 million due primarily to

- a net increase of $65 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during 2013, partially offset by lower average gas prices, and
- an increase of $29 million due primarily to higher average gas prices partially offset by lower sales volumes to third party customers.

Generation Revenues decreased $3 million due primarily to

- a decrease of $70 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts,
- a net decrease of $73 million due to lower volumes on wholesale load contracts in the PJM and New England regions, and
- lower net revenues of $56 million due primarily to MTM losses in 2013 resulting from an increase in prices on forward positions in the PJM region, partially offset by higher generation sold in the PJM and New England regions at lower average realized prices in PJM,

- partially offset by a net increase of $196 million due to higher capacity and other revenues resulting from higher auction prices and an increase in operating reserve revenue in PJM.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased $87 million due to

- Gas costs increased $48 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due to colder average temperatures in 2013, partially offset by lower average gas inventory costs.
- Generation costs increased $39 million due primarily to $119 million of higher fuel costs, reflecting the utilization of higher volumes of coal and oil and higher nuclear fuel costs, and higher unrealized natural gas prices. The increase was partially offset by $27 million of lower energy purchases primarily in the PJM region as a result of lower load contract demand in 2013 and a decrease of $53 million in congestion costs.

Operation and Maintenance increased $37 million due primarily to $50 million in costs incurred from Superstorm Sandy in 2013 at our fossil plants, and higher outage and maintenance costs in 2013, mainly at our Bergen gas-fired plant and our coal-fired Conemaugh plant in Pennsylvania. This was partially offset by the recognition of the $25 million insurance recovery related to Superstorm Sandy.

Depreciation and Amortization increased $14 million due primarily to a higher depreciable asset base, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012 and completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012.

Other Income and (Deductions) increased $9 million due primarily to higher net earnings from the NDT Fund in 2013.

Other-Than-Temporary Impairments decreased $8 million due primarily to a decrease in impairments on the NDT Fund in 2013.

Interest Expense decreased $3 million due primarily to a decrease from lower outstanding debt in 2013 resulting from certain debt redeemed prior to maturity in 2012, partially offset by higher interest costs in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense decreased $11 million in 2013 due primarily to lower pre-tax income.

PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)	Six Months Ended June 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$121	$101	$20	$300	$298	$2

For the three months ended June 30, 2013, the primary reason for the $20 million increase in Net Income was higher transmission revenues due to increased investments in transmission projects.

For the six months ended June 30, 2013, the primary reasons for the $2 million increase in Net Income were

- higher transmission revenues due to increased investments in transmission projects, and
- higher Operation and Maintenance Expense primarily due to the Societal Benefits Charge (SBC) and the Capital Infrastructure programs (CIPs),
- partially offset by higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012.

The quarter and year-to-date details for these variances are discussed below:

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2013	2012	2013 vs. 2012		2013	2012	2013 vs. 2012	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$1,423	$1,407	$16	1	$3,418	$3,346	$72	2
Energy Costs	580	622	(42)	(7)	1,547	1,624	(77)	(5)
Operation and Maintenance	369	350	19	5	796	726	70	10
Depreciation and Amortization	207	188	19	10	422	378	44	12
Taxes Other Than Income Taxes	14	20	(6)	(30)	35	49	(14)	(29)
Other Income (Deductions)	14	11	3	27	26	21	5	24
Interest Expense	75	74	1	1	148	147	1	1
Income Tax Expense	71	63	8	13	196	145	51	35

Three Months Ended June 30, 2013 As Compared to 2012

Operating Revenues increased $16 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $38 million due primarily to an increase in transmission revenues.

- Transmission revenues were $46 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues increased $1 million due primarily to base rate increase of $8 million due to the roll in of the CIP from clause mechanism to inclusion in base rates, and higher Green Program Recovery Charges (GPRC) of $5 million, partially offset by lower Transitional Energy Facilities Assessment (TEFA) revenue of $6 million due to a lower TEFA rate and lower CIP revenue of $6 million due to the roll in to base rates.
- Gas distribution revenues decreased $9 million due primarily to lower Weather Normalization Clause (WNC) revenue of $22 million, partially offset by $10 million from higher sales volumes and $3 million of base rate increase due to the roll in of the CIP programs to base rates.

Clause Revenues increased $18 million due primarily to higher Securitization Transition Charge (STC) revenues of $10 million and higher SBC of $7 million. The changes in SBC and STC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in Operation and Maintenance (O&M), Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC or STC collections.

Other Operating Revenues increased $2 million due primarily to increased revenues from our appliance repair business.

Commodity Revenue decreased $42 million due to lower Electric revenues, partially offset by higher Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $57 million due primarily to $29 million in lower BGS revenues and $28 million in lower revenues from a lower volume of sales of Non-Utility Generation (NUG) energy and lower Non-Utility Generation Charges (NGC) due to lower tariff rates. BGS sales decreased 6% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales increased by 3%.
- Gas revenues increased $15 million due to higher BGSS volumes of $11 million primarily due to weather and higher BGSS prices of $4 million. The average price of natural gas was 3% higher in 2013 than in 2012.

Energy Costs decreased $42 million. This is entirely offset by Commodity Revenue.

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Electric costs decreased $57 million or 11% due to $57 million in lower BGS and NUG volumes and $19 million of lower BGS and NUG prices, partially offset by $19 million for increased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.

- Gas costs increased $15 million or 13% due to $11 million or 9% in higher sales volumes due primarily to weather and $4 million or 3% in higher prices.

Operation and Maintenance increased $19 million, due primarily to a $20 million increase in costs recognized related primarily to SBC and CIP. Due to the nature of the SBC and CIP clause mechanisms, this is entirely offset in revenues.

Depreciation and Amortization increased $19 million due primarily to

- a $13 million increase in amortization of Regulatory Assets, and
- a $6 million increase in depreciation of additional plant in service.

Taxes Other Than Income Taxes decreased $6 million due to a lower TEFA rate for electric and gas, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $3 million was due primarily to an increase in Solar Loan interest income.

Interest Expense increased due primarily to higher average debt balances.

Income Tax Expense increased $8 million due primarily to higher pre-tax income.

Six Months Ended June 30, 2013 As Compared to 2012

Operating Revenues increased $72 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $92 million due primarily to an increase in transmission revenues.

- Transmission revenues were $85 million higher due to net rate increases resulting primarily from increased capital investments.
- Gas distribution revenues increased $12 million due primarily to $53 million from higher sales volumes and base rate increase of $14 million from the CIP base rate adjustment, partially offset by lower WNC revenue of $55 million.
- Electric distribution revenues decreased $5 million due primarily to lower TEFA revenue of $12 million due to a lower TEFA rate and lower CIP revenue of $11 million, partially offset by a base rate increase of $12 million from the CIP base rate adjustment, higher GPRC of $5 million and higher sales volumes of $1 million.

Clause Revenues increased $51 million due primarily to higher SBC of $25 million and higher STC revenues of $24 million. The changes in SBC and STC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC or STC collections.

Other Operating Revenues increased $6 million due primarily to increased revenues from our appliance repair business.

Commodity Revenue decreased $77 million due to lower Electric revenues, partially offset by higher Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $175 million due primarily to $123 million in lower BGS revenues and $52 million in lower revenues from a lower volume of sales of Non-Utility Generation (NUG) energy and lower Non-Utility Generation Charges (NGC) due to lower tariff rates. BGS sales decreased 6% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales increased by 3%.
- Gas revenues increased $98 million due to higher BGSS volumes of $92 million and higher BGSS prices of $6 million. The average price of natural gas was 1% higher in 2013 than in 2012.

Energy Costs decreased $77 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $175 million or 16% due to $106 million in lower BGS and NUG volumes, $43 million of lower BGS and NUG prices, and $26 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs increased $98 million or 17% due to $92 million or 16% in higher sales volumes due primarily to weather and $6 million or 1% in higher prices.

Operation and Maintenance increased $70 million, of which the most significant components were

- a $50 million increase in costs recognized related primarily to SBC and CIP. Due to the nature of the SBC and CIP clause mechanisms, this is entirely offset in revenues,
- a $8 million increase in costs relating to repairs from Superstorm Sandy and a colder winter, and
- a $6 million increase in appliance service costs.

Depreciation and Amortization increased $44 million due primarily to

- a $30 million increase in amortization of Regulatory Assets, and
- a $13 million increase in depreciation of additional plant in service.

Taxes Other Than Income Taxes decreased $14 million due to a lower TEFA rate for electric and gas, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $5 million was due primarily to an increase in Solar Loan interest income.

Interest Expense increased due primarily to higher average debt balances.

Income Tax Expense increased $51 million due primarily to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012 and higher pre-tax income.

Energy Holdings

	Three Months Ended June 30,		Increase/ (Decrease)	Six Months Ended June 30,		Increase/ (Decrease)
	2013	2012	2013 vs. 2012	2013	2012	2013 vs. 2012
	Millions					
Net Income	$4	$2	$2	$4	$42	$(38)

For the six months ended June 30, 2013, the primary reason for the $38 million decrease in Net Income was the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in the prior year.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our three direct operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund capital expenditures and shareholder dividend payments.

For the six months ended June 30, 2013, our operating cash flow decreased $35 million as compared to the same period in 2012. The net change was due primarily to net changes from Power and PSE&G, as discussed below.

Power

Power’s operating cash flow increased $2 million from $852 million to $854 million for the six months ended June 30, 2013, as compared to the same period in 2012, primarily resulting from a decrease in taxes paid of $58 million, partially offset by lower earnings and an increase of $44 million in margin deposits.

PSE&G

PSE&G’s operating cash flow decreased $38 million from $459 million to $421 million for the six months ended June 30, 2013, as compared to the same period in 2012, due primarily to a decrease of $102 million related to higher customer billings due to colder weather, and $106 million related to higher tax payments. These were partially offset by higher earnings and an increase of $70 million due to a net change in regulatory deferrals primarily related to the recovery of gas costs and collection of Gas Weather Normalization Charges, offset by higher payments for storm related costs.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our credit facilities are provided by a diverse bank group. In March 2013, Power, PSEG and PSE&G amended their respective 5-year credit agreements scheduled to end in 2016, extending the expiration dates from April 2016 to March 2018. Of the total commitments of $2.1 billion under these agreements, $2.0 billion has been extended until 2018. The commitments for the $100 million balance will terminate in 2016. As of June 30, 2013, our total credit capacity was $4.3 billion.

As of June 30, 2013, no single institution represented more than 8% of the total commitments in our credit facilities.

As of June 30, 2013, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of June 30, 2013 were as follows:

Company/Facility	As of June 30, 2013 Total Facility Millions	Usage		Available Liquidity	Expiration Date	Primary Purpose
PSEG						
5-year Credit Facility	$500	$5	(D)	$495	Mar 2017	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—		500	Mar 2018	CP Support/Funding/Letters of Credit
Total PSEG	$1,000	$5		$995		
Power						
5-year Credit Facility	$1,600	$54	(D)	$1,546	Mar 2017	Funding/Letters of Credit
5-year Credit Facility (B)	1,000	—		1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100	(D)	—	Sept 2015	Letters of Credit
Total Power	$2,700	$154		$2,546		
PSE&G						
5-year Credit Facility (C)	$600	$170	(E)	$430	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	$600	$170		$430		
Total	$4,300	$329		$3,971		

(A) In April 2016, this facility will be reduced by $23 million.
(B) In April 2016, this facility will be reduced by $48 million.
(C) In April 2016, this facility will be reduced by $29 million.
(D) Includes amounts related to letters of credit outstanding.
(E) Includes amounts related to CP and letters of credit outstanding.

Long-Term Debt Financing

PSE&G has $300 million of 5.38% MTN maturing in September 2013 and $275 million of 6.33% MTN maturing in November 2013. For a discussion of our long-term debt transactions during 2013, see Note 10. Changes in Capitalization.

Common Stock Dividends

On July 16, 2013, the Board of Directors declared a quarterly dividend of $0.36 per share of common stock for the third quarter of 2013. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant. For information related to cash dividends on our common stock, see Note 16. Earnings Per Share and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2013, S&P upgraded the corporate credit ratings on PSEG, Power and PSE&G to BBB+ from BBB and PSE&G's Mortgage Bond rating to A from A-. PSEG's, Power's and PSE&G's outlooks were changed to stable from positive. In May 2013, Moody's published updated credit opinions on PSEG, Power and PSE&G. PSEG's, Power's and PSE&G's ratings and outlooks remained unchanged. In July 2013, Fitch published updated research on PSEG, Power and PSE&G which kept their ratings and outlooks unchanged.

	Moody’s (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	Stable	Stable	Stable
Commercial Paper	P2	A2	F2
Power			
Outlook	Stable	Stable	Stable
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	Stable	Stable	Stable
Mortgage Bonds	A1	A	A+
Commercial Paper	P2	A2	F2

(A) Moody’s ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1+ (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1+ (highest) to D (lowest) for short-term securities.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. PSE&G has increased its projected base level capital expenditures by $215 million through 2015, as compared to the amounts disclosed in our Form 10-K for the year ended December 31, 2012. This increase primarily reflects our projected additional spending during the period under our Solar Loan III and Solar 4 All Extension programs which were approved by the BPU in May 2013. There were no other material changes to our projected capital expenditures at Power, PSE&G or Energy Holdings as compared to amounts disclosed in our Form 10-K for the year ended December 31, 2012. See Note 9. Commitments and Contingent Liabilities for additional information. Our revised projected capital construction and investment expenditures for the next three years are presented in the table below.

	2013	2014	2015
Power:		Millions	
Baseline Maintenance	$215	$170	$200
Environmental/Regulatory	70	70	15
Nuclear Expansion	115	125	90
Total Power	$400	$365	$305
PSE&G:			
Transmission			
Reliability Enhancements	$1,230	$1,040	$550
Facility Replacement	265	145	160
Support Facilities	10	15	10
Environmental/Regulatory	5	—	—
Distribution			
Reliability Enhancements	85	75	75
Facility Replacement	140	150	175
Support Facilities	45	50	45
New Business	125	130	135
Environmental/Regulatory	35	35	30
Renewables	105	125	125
Total PSE&G	$2,045	$1,765	$1,305
Non-Utility Renewables	50	—	—
Other	45	40	30
Total PSEG	$2,540	$2,170	$1,640

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses. MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

Three Months Ended June 30, 2013	MTM VaR Millions
95% Confidence Level,	
Loss could exceed VaR one day in 20 days	
Period End	$19
Average for the Period	$15
High	$20
Low	$9
99.5% Confidence Level,	
Loss could exceed VaR one day in 200 days	
Period End	$30
Average for the Period	$23
High	$32
Low	$14

See Note 11. Financial Risk Management Activities for a discussion of credit risk.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer (CEO) and Chief Financial Officer (CFO) of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The CFO and CEO of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the second quarter of 2013 that have materially affected, or are reasonably likely to materially affect, each registrant’s internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. Certain information reported under Item 3 of Part I of the 2012 Annual Report on Form 10-K and under Item 1 of Part II of the Quarterly Report on Form 10-Q for the quarter ended March 31, 2013 is updated below. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2012 Annual Report on Form 10-K and under Item 1 of Part II of the Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, see Note 9. Commitments and Contingent Liabilities and Item 5. Other Information.

Superstorm Sandy

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. PSEG is seeking recovery from its insurers for the property damage, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. PSEG has recorded proceeds of $50 million from its insurance carriers as advance payments, $25 million of which was recognized in this quarter and $25 million was recognized in the fourth quarter of 2012. PSEG does not believe that it has a basis for estimating additional probable insurance recoveries at this time. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. The dispute concerns whether certain sub-limits in the policies apply to damage to property caused by Superstorm Sandy's storm surge. In that lawsuit, PSEG stated that its estimate of the total costs required to restore damaged facilities to their pre-Superstorm Sandy condition was approximately $426 million. Of these costs, $364 million and $62 million related to Power and PSE&G, respectively. No ruling has been issued on the suit.

Con Edison (Con Ed)

December 31, 2012 Form 10-K page 38. In 2001, Con Ed filed a complaint with the FERC against PSE&G, PJM and NYISO asserting a failure to comply with agreements between PSE&G and Con Ed covering 1,000 MW of transmission. In 2010, the FERC approved a settlement agreement of this matter entered into by PSE&G, Con Ed, PJM, NYISO and others, which provided the basis for moving forward with Con Ed upon the contracts' expiration and resolved all issues associated with the existing contracts. One party to the proceeding, however, appealed the FERC's approval to the D.C. Circuit Court of Appeals. By order dated June 14, 2013, the court denied the appeal, thereby upholding FERC's approval of the settlement and making the settlement agreement effective.

ITEM 1A. RISK FACTORS

There no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2012 Annual Report on Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the second quarter of 2013:

Three Months Ended June 30, 2013	Total Number of Shares Purchased	Average Price Paid per Share
April 1 - April 30	—	$—
May 1 - May 31	182,500	$35.85
June 1 - June 30	3,500	$33.03

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ITEM 5. OTHER INFORMATION

Certain information reported in the 2012 Annual Report on Form 10-K and Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013 is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2012 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the Quarter Ended March 31, 2013. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

BUSINESS OPERATIONS AND STRATEGY

Energy Holdings

Products and Services

December 31, 2012 Form 10-K page 13. Our ten-year contract, Operations Services Agreement (OSA), for the management of the Long Island Power Authority (LIPA) transmission and distribution system by PSEG Long Island LLC (PSEG LI) is scheduled to commence on January 1, 2014. On July 29, 2013, the Governor of New York signed legislation that will restructure LIPA, pursuant to which PSEG LI may undertake an expanded role in the management of LIPA's transmission and distribution system and other aspects of its operations in accordance with a proposed revised contract that is currently under negotiation. Assuming that an agreement is reached on the terms of a revised contract, implementation will depend, in part, on (i) issuance of a Private Letter Ruling by the Internal Revenue Service (IRS) on the continued tax-exempt status of certain LIPA debt securities and (ii) a disclaimer of jurisdiction by the FERC with regard to the contract. No assurances can be given as to the outcome of the negotiations or the actions of the IRS or the FERC.

We continue to take all necessary steps in connection with the expected January 1, 2014 commencement of our management responsibilities in accordance with the existing OSA.

FEDERAL REGULATION

FERC

PJM, the New York Independent System Operator (NYISO), and the Independent System Operator-New England (ISO-NE) each have capacity markets that have been approved by the FERC.

Capacity Market Issues—PJM

December 31, 2012 Form 10-K page 16. RPM is a locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active, and there is currently significant discussion about (i) the future role of demand response in the RPM market, including examining how demand response resources should be paid and how these resources and programs - both existing and planned - should be measured and verified to ensure their availability, (ii) the future process for submitting below Minimum Offer Price Rule (MOPR) bids by subsidized generation into the capacity market, as further discussed below and (iii) the impact of “seams” issues on the PJM capacity market, such as the extent to which the rules governing generation located within PJM are being equally applied to generation imported into PJM from the Midwest Independent System Operator (MISO), as further discussed below.

Capacity Market Issues—MISO

MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. Recently the difference between the MISO and PJM capacity markets has been highlighted, as significant amounts of MISO generation are being exported to PJM, and MISO is seeking to facilitate additional exports. The FERC is currently examining the "capacity portability" issue. To the extent that MISO generation is not subject to the same types of rules and requirements as generation located within PJM, Power could be adversely impacted.

Capacity Market Issues—Long-Term Capacity Agreement Pilot Program Act (LCAPP)

December 31, 2012 Form 10-K page 16 and March 31, 2013 Form 10-Q page 70. In 2011, the State of New Jersey concluded that new natural gas-fired generation was needed and enacted the LCAPP Act to subsidize approximately

2,000 MW of new generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey Electric Distribution Companies (EDCs). The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into the SOCAs as directed by the State, but did so under protest reserving their rights. In July 2013, the SOCA contract with New Jersey Power Development LLC, a subsidiary of NRG Energy, Inc., was terminated early as a result of a default by the generator. The generator has accepted this early termination and this SOCA contract is no longer in effect.

Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and the appeal remains pending. In addition, the LCAPP Act has been challenged on constitutional grounds in federal court. We are currently awaiting a decision by the federal court.

Maryland has also taken action to subsidize above-market new generation. On April 16, 2013, the Maryland Public Service Commission (PSC) issued an order directing the Maryland utility companies to execute a contract with CPV to build a new 661 MW natural gas-fired, combined cycle station in Maryland with an in-service date of June 2015. We have joined other generators in challenging Maryland's actions on constitutional grounds in federal court and we are currently awaiting a decision by the court in that case.

These efforts to artificially depress prices in the wholesale capacity markets were intended to be mitigated by the MOPR approved by the FERC. The MOPR was intended to restrict new generation from bidding in RPM at less than a minimum level established by PJM's Tariff, or a cost-based bid to the extent that the generator can demonstrate that its costs are lower than the MOPR. However, we do not believe these rules have worked as intended and have not protected the market against price suppression efforts. At the direction of the FERC, PJM has begun a stakeholder proceeding, the purpose of which is to develop an enhanced process applicable to subsidized generation seeking to bid into RPM at less than MOPR. We are currently working to ensure that this unit-specific review is both effective and transparent.

Transmission Regulations—Transmission Policy Developments

December 31, 2012 Form 10-K page 17 and March 31, 2013 Form 10-Q page 71. In 2010, the FERC initiated a proceeding to evaluate whether reforms to current transmission planning and cost allocation rules were necessary to stimulate additional transmission development. The FERC ultimately concluded in Order No. 1000, subject to certain exceptions, that the incumbent transmission owner should not always have a “right of first refusal” (ROFR) to construct and own transmission projects in its service territory. We have challenged the FERC's elimination of the ROFR in federal court, which challenge remains pending. The FERC has issued an order regarding PJM's implementation of these new transmission planning and cost allocation rules, under which the construction of certain types of transmission projects will no longer be subject to a ROFR for incumbents. The FERC's order also approved the “state agreement approach,” under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

Transmission Regulations—Transmission Rate Proceedings

December 31, 2012 Form 10-K page 18 and March 31, 2013 Form 10-Q page 71. In February 2013, several state utility commissions and consumer advocates, including the BPU and the New Jersey Division of Rate Counsel, filed a complaint at FERC challenging the base return on equity and formula transmission rate implementation protocols of transmission owners in Maryland, Pennsylvania, Delaware and New Jersey.

While we are not the subject of this complaint nor those reported in our 2012 Form 10-K, the results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

On June 7, 2013, the U.S. Seventh Circuit Court of Appeals issued a decision vacating a FERC order that had prevented MISO from allocating the costs of Multi-Value transmission projects (MVP), being built primarily to move renewable generation to load within MISO, to customers within PJM. The court held that the FERC had not adequately justified its decision and remanded the case back to the FERC to explain why such costs should not be allocated to PJM customers. Depending on the resolution of the remand proceeding at FERC, this court ruling may have adverse impacts on our business and our customers.

Nuclear Regulatory Commission (NRC)

December 31, 2012 Form 10-K page 19 and March 31, 2013 Form 10-Q page 71. On March 19, 2013, the NRC initiated a rulemaking process for improvements to venting systems at 31 U.S. boiling water reactors (BWRs) with “Mark I” and “Mark II” containments (similar to those at Fukushima), which include our Hope Creek Unit and Peach

Bottom Units 2 and 3. On June 6, 2013, the NRC issued orders requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vents with containment venting systems designed and installed to remain functional during severe accident conditions. For our Hope Creek and Peach Bottom units, final installation of the required modifications is expected to occur during the planned refueling outages in 2016-2018. The NRC is currently performing a technical evaluation to support rulemaking on the potential for vent filtering requirements. That evaluation is expected to be completed in March 2014. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident in Japan in 2011. We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

STATE REGULATION

Rates

Storm Damage Deferral

December 31, 2012 Form 10-K page 20. In December 2012, the BPU granted our request to defer on our books actually incurred prudent otherwise unreimbursed, incremental storm restoration costs not otherwise recoverable through base rates or insurance related to our gas and electric distribution systems associated with extraordinary storms, including Hurricane Irene and Superstorm Sandy. In February 2013, the BPU announced that it would initiate a generic proceeding to evaluate the prudency of extraordinary, storm-related costs incurred by all of the regulated utilities as a result of the natural disasters experienced in New Jersey in 2011 and 2012.

Energy Strong Program

December 31, 2012 Form 10-K page 20 and March 31, 2013 Form 10-Q page 71. In February 2013, we filed a petition with the BPU seeking approval of certain investments we recommend making to our BPU jurisdictional electric and gas system to harden and improve resiliency for the future through a clause recovery mechanism. We have continued to respond to data requests from the BPU and the New Jersey Division of Rate Counsel. In June 2013, the BPU issued an order designating a Presiding Officer for the Energy Strong Proceeding. The appointment of this Presiding Officer will enable the establishment of a procedural schedule for the proceeding. We cannot predict the outcome of this matter which remains pending before the BPU.

Energy Supply

BGSS

December 31, 2012 Form 10-K page 21. In September 2012, the BPU approved the Stipulation which lowered our BGSS rate effective October 1, 2012 on a provisional basis. In May 2013, the BPU approved a Stipulation that made the current BGSS rate final. Additionally, in May 2013 we made our annual BGSS filing with the BPU requesting no change to the current rate for the next BGSS period effective October 1, 2013 through September 30, 2014.

Energy Policy

Solar

March 31, 2013 Form 10-Q page 72. In May 2013, the BPU approved increased spending on renewable energy under our Solar Loan and Solar 4 All investment programs (Solar Loan III and Solar 4 All Extension, respectively). The Orders authorize us to invest up to $199 million on new solar (98MW) as part of the Solar Loan III program and provide for us to invest up to $247 million to develop new solar capacity (45MW), including a return on investment at a return on equity of 10%.

BPU Storm Generic Proceedings

March 31, 2013 Form 10-Q page 72. In March 2013, the BPU initiated two generic proceedings with the New Jersey utilities, including PSE&G. The first was an Order to evaluate the prudency of storm costs incurred in 2011 and 2012 and the second to evaluate major storm event mitigation proposals. In June 2013, we made our compliance filing in the storm cost prudency proceeding, providing outage information, capital expenditures, operation and maintenance (O&M) expenses and incremental O&M expenses. The review of the prudency of these expenses is now pending before the BPU. We cannot predict the outcome of this review.

BPU Storm Report

December 31, 2012 Form 10-K page 22. In 2011, the BPU commenced an investigation of all four New Jersey electric utilities, including PSE&G, to examine their preparations, performance and restoration efforts during Hurricane Irene and the October 2011 snow storm. In late 2012, the BPU commenced an investigation regarding the state of preparedness and responsiveness of the electric distribution companies prior to, during and after Superstorm Sandy. Following the completion of a report by its consultant, the BPU issued an order in January 2013, ordering the utilities to take specific action to improve their preparedness and responses to major storms. There are 103 separate measures contained in the Order, with most of the measures requiring utility implementation by September 2013. In May 2013, the BPU augmented its January 2013 order by directing the electric utilities to implement eight additional new requirements related to improving communications with customers during extreme weather events. PSE&G is in the process of implementing these BPU requirements.

ENVIRONMENTAL MATTERS

Air Pollution Control

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation

March 31, 2013 Form 10-Q page 72. On March 29 and April 1, 2013, we filed petitions at the EPA and in federal court, respectively, challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued on January 30, 2013. Among other things, the final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In our appeal, we are seeking more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. On June 28, 2013, the EPA announced that it would reconsider certain other items included in the final rule that are also subject to the appeal.

Cross-State Air Pollution Rule (CSAPR)

December 31, 2012 Form 10-K page 24 and March 31, 2013 Form 10-Q page 72. On July 6, 2011, the EPA issued the final CSAPR. CSAPR limits power plant emissions of SO_2 and annual and ozone season NOx in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS).

In August 2012, the U.S. Court of Appeals of the D.C. Circuit (D.C. Court) vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. In October 2012, the EPA filed a request for rehearing which the D.C. Court denied on January 24, 2013. On June 24, 2013, the Supreme Court announced that it would review the D.C. Court's decision.

We currently anticipate that CSAPR, if implemented, will not have a material adverse impact to our capital investment program or our units' operations.

Climate Change

CO_2 Regulation Under the Clean Air Act (CAA)

December 31, 2012 Form 10-K page 24. In April 2013, several industrial groups petitioned the Supreme Court to review various EPA rules issued under the CAA, including the Tailoring Rule, to regulate greenhouse gas (GHG) emissions, including $CO_{2.}$ The Tailoring Rule requires a new source or an existing source which undergoes a major modification, to evaluate and perhaps install best available control technology (BACT) for GHG emissions.

The EPA's BACT guidance does not define the specific technologies that should be considered BACT. The guidance does emphasize the use of energy efficiency, and specifically states that the technology of storing CO_2 under the earth, also known as carbon capture and storage, is not yet mature enough to be considered a viable alternative at this stage.

In April 2012, the EPA published the proposed New Source Performance Standards (NSPS) for GHG for new power plants only. Typically, new or modified sources must employ BACT which is defined on a case-by-case basis and can be no less stringent than the applicable NSPS. Thus, for new power plants where the proposed NSPS identifies the applicable standard, if adopted as proposed, all permit decisions regarding BACT and application completeness should be made to reflect at least the level of stringency contained in those standards. On June 25, 2013, the President directed the EPA to propose revised NSPS for new power plants by September 20, 2013, propose GHG regulations for existing power plants by June 1, 2014, finalize such regulations by June 1, 2015 and require states to submit GHG implementation regulations by June 30, 2016.

Water Pollution Control

Cooling Water Intake Structure Regulation

December 31, 2012 Form 10-K page 25. In April 2011, the EPA published a proposed rule to establish marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. In July 2012, the EPA and environmental groups agreed to delay the deadline to June 27, 2013 for finalization of the Rule. On June 27, 2013, the EPA and environmental groups agreed to further extend the deadline to November 4, 2013.

If the rule were to be adopted as proposed, the impact on us would be material since the majority of our electric generating stations would be affected. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Note 9. Commitments and Contingent Liabilities for additional information.

Steam Electric Effluent Guidelines

March 31, 2013 Form 10-Q page 72. On April 19, 2013, the EPA issued notice of a proposed rule that would further limit the discharge of pollutants in wastewater from the operation of coal-fired generating facilities. The EPA has established September 20, 2013 as the date comments must be filed. Our co-owned Keystone and Conemaugh facilities continue to use technologies that generate these wastewater discharges. However, our other coal-fired facilities no longer discharge many of these types of wastewater pollutants. We are unable to predict the impact on Keystone and Conemaugh but do not believe there would be any material impact on our other coal-fired facilities.

Fuel and Waste Disposal

Nuclear Fuel Disposal

December 31, 2012 Form 10-K page 26. The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the U.S. Department of Energy (DOE) conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit seeking suspension of the Nuclear Waste Fee. In June 2012, the U.S. Court of Appeals for the District of Columbia (D.C. Court) ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee. In January 2013, the DOE completed its assessment and concluded that fee collection should be maintained. On January 31, 2013, motions were filed with the D.C. Court seeking to reopen the case and set a schedule for expedited review of the DOE fee adequacy report. In June 2013, the D.C. Court scheduled oral arguments for September 2013.

ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
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Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 4:	Supplemental Indenture, dated May 1, 2013
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) 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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ DEREK M. DIRISIO
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: July 30, 2013

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) 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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ DEREK M. DIRISIO
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: July 30, 2013

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) 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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ DEREK M. DIRISIO
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: July 30, 2013