PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-Q
August 01, 2014
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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, 2014
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 15, 2014, Public Service Enterprise Group Incorporated had outstanding 505,886,756 shares of its sole class of Common Stock, without par value.

As of July 15, 2014, 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.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical 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,” “forecast,” “project,” variations of such words and similar expressions 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 filings we make with the United States Securities and Exchange Commission (SEC), including our Annual Report on Form 10-K and subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. 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 and enforcement 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 manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- 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 obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as competition for certain 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,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and

- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

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.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$2,249	$2,310	$5,472	$5,096
OPERATING EXPENSES				
Energy Costs	789	755	2,145	1,910
Operation and Maintenance	800	646	1,656	1,356
Depreciation and Amortization	295	283	601	573
Taxes Other Than Income Taxes	—	14	—	35
Total Operating Expenses	1,884	1,698	4,402	3,874
OPERATING INCOME	365	612	1,070	1,222
Income from Equity Method Investments	3	3	7	5
Other Income	62	52	110	113
Other Deductions	(10)	(13)	(22)	(42)
Other-Than-Temporary Impairments	(2)	(2)	(4)	(4)
Interest Expense	(94)	(101)	(191)	(203)
INCOME BEFORE INCOME TAXES	324	551	970	1,091
Income Tax Expense	(112)	(218)	(372)	(438)
NET INCOME	$212	$333	$598	$653
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):				
BASIC	505,875	505,900	505,976	505,921
DILUTED	508,056	507,381	507,949	507,301
NET INCOME PER SHARE:				
BASIC	$0.42	$0.66	$1.18	$1.29
` DILUTED	$0.42	$0.66	$1.18	$1.29
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$0.37	$0.36	$0.74	$0.72

See Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
NET INCOME	$212	$333	$598	$653
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(9), $16, $(12) and $(11) for the three and six months ended 2014 and 2013, respectively	11	(16)	13	11
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $1, $(2) and $3 for the three and six months ended 2014 and 2013, respectively	1	—	3	(4)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(1), $(7), $(3) and $(14) for the three and six months ended 2014 and 2013, respectively	2	9	6	19
Other Comprehensive Income (Loss), net of tax	14	(7)	22	26
COMPREHENSIVE INCOME	$226	$326	$620	$679

See Notes to Condensed Consolidated Financial Statements.

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

	June 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$570	$493
Accounts Receivable, net of allowances of $58 and $56 in 2014 and 2013, respectively	1,294	1,203
Tax Receivable	101	109
Unbilled Revenues	238	300
Fuel	426	545
Materials and Supplies, net	476	479
Prepayments	249	89
Derivative Contracts	73	98
Deferred Income Taxes	104	24
Regulatory Assets	229	243
Other	34	31
Total Current Assets	3,794	3,614
PROPERTY, PLANT AND EQUIPMENT	30,709	29,713
Less: Accumulated Depreciation and Amortization	(8,399)	(8,068)
Net Property, Plant and Equipment	22,310	21,645
NONCURRENT ASSETS		
Regulatory Assets	2,584	2,612
Regulatory Assets of Variable Interest Entities (VIEs)	355	476
Long-Term Investments	1,315	1,313
Nuclear Decommissioning Trust (NDT) Fund	1,777	1,701
Long-Term Receivable of VIE	409	—
Other Special Funds	657	613
Goodwill	16	16
Other Intangibles	90	33
Derivative Contracts	45	163
Restricted Cash of VIEs	24	24
Other	324	312
Total Noncurrent Assets	7,596	7,263
TOTAL ASSETS	$33,700	$32,522

See Notes to Condensed Consolidated Financial Statements.

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

	June 30, 2014	December 31, 2013
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$844	$544
Securitization Debt of VIEs Due Within One Year	251	237
Commercial Paper and Loans	—	60
Accounts Payable	1,104	1,222
Derivative Contracts	88	76
Accrued Interest	95	95
Accrued Taxes	93	37
Clean Energy Program	200	142
Obligation to Return Cash Collateral	122	119
Regulatory Liabilities	176	43
Other	490	488
Total Current Liabilities	3,463	3,063
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,197	7,107
Regulatory Liabilities	169	233
Regulatory Liabilities of VIEs	11	11
Asset Retirement Obligations	697	677
Other Postretirement Benefit (OPEB) Costs	1,077	1,095
OPEB Costs of Servco	314	—
Accrued Pension Costs	122	121
Accrued Pension Costs of Servco	93	—
Clean Energy Program	27	—
Environmental Costs	381	414
Derivative Contracts	36	31
Long-Term Accrued Taxes	230	180
Other	107	119
Total Noncurrent Liabilities	10,461	9,988
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,782	7,587
Securitization Debt of VIEs	134	259
Project Level, Non-Recourse Debt	16	16
Total Long-Term Debt	7,932	7,862
STOCKHOLDERS’ EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2014 and 2013—533,556,660 shares	4,865	4,861
Treasury Stock, at cost, 2014— 27,716,798 shares; 2013— 27,699,398 shares	(630)	(615)
Retained Earnings	7,681	7,457

Accumulated Other Comprehensive Loss	(73)	(95)
Total Common Stockholders’ Equity	11,843	11,608
Noncontrolling Interest	1	1
Total Stockholders’ Equity	11,844	11,609
Total Capitalization	19,776	19,471
TOTAL LIABILITIES AND CAPITALIZATION	$33,700	$32,522

See Notes to Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$598	$653
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	601	573
Amortization of Nuclear Fuel	98	95
Provision for Deferred Income Taxes (Other than Leases) and ITC	70	146
Non-Cash Employee Benefit Plan Costs	24	122
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(44)	(26)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	297	20
Change in Accrued Storm Costs	(3)	(81)
Net Change in Other Regulatory Assets and Liabilities	192	62
Cost of Removal	(50)	(46)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(59)	(47)
Net Change in Margin Deposit	(234)	(8)
Net Change in Certain Current Assets and Liabilities	(53)	32
Employee Benefit Plan Funding and Related Payments	(50)	(194)
Other	61	42
Net Cash Provided By (Used In) Operating Activities	1,448	1,343
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,229)	(1,406)
Proceeds from Sales of Capital Leases and Investments	11	42
Proceeds from Sales of Available-for-Sale Securities	584	681
Investments in Available-for-Sale Securities	(599)	(684)
Other	(49)	(12)
Net Cash Provided By (Used In) Investing Activities	(1,282)	(1,379)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(60)	(106)
Issuance of Long-Term Debt	500	900
Redemption of Long-Term Debt	—	(450)
Redemption of Securitization Debt	(111)	(106)
Cash Dividends Paid on Common Stock	(374)	(364)
Other	(44)	(53)
Net Cash Provided By (Used In) Financing Activities	(89)	(179)
Net Increase (Decrease) in Cash and Cash Equivalents	77	(215)
Cash and Cash Equivalents at Beginning of Period	493	379
Cash and Cash Equivalents at End of Period	$570	$164
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$296	$138
Interest Paid, Net of Amounts Capitalized	$192	$194

Accrued Property, Plant and Equipment Expenditures	$240	$222

See Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$986	$1,193	$2,686	$2,644
OPERATING EXPENSES				
Energy Costs	520	495	1,564	1,355
Operation and Maintenance	327	280	629	563
Depreciation and Amortization	72	67	144	133
Total Operating Expenses	919	842	2,337	2,051
OPERATING INCOME	67	351	349	593
Income from Equity Method Investments	3	5	7	8
Other Income	46	35	79	82
Other Deductions	(9)	(10)	(19)	(38)
Other-Than-Temporary Impairments	(2)	(2)	(4)	(4)
Interest Expense	(29)	(29)	(61)	(59)
INCOME BEFORE INCOME TAXES	76	350	351	582
Income Tax Expense	(22)	(140)	(133)	(231)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$54	$210	$218	$351

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
NET INCOME	$54	$210	$218	$351
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(9), $16, $(11) and $(11) for the three and six months ended 2014 and 2013, respectively	9	(14)	11	13
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $1, $(2) and $3 for the three and six months ended 2014 and 2013, respectively	2	(1)	3	(5)
Pension/OPEB adjustment, net of tax (expense) benefit of $(1), $(6), $(3) and $(11) for the three and six months ended 2014 and 2013, respectively	2	8	5	17
Other Comprehensive Income (Loss), net of tax	13	(7)	19	25
COMPREHENSIVE INCOME	$67	$203	$237	$376

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

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$6	$6
Accounts Receivable	408	338
Accounts Receivable—Affiliated Companies, net	102	333
Short-Term Loan to Affiliate	740	790
Fuel	426	545
Materials and Supplies, net	349	362
Derivative Contracts	55	57
Prepayments	13	13
Deferred Income Taxes	78	30
Other	2	2
Total Current Assets	2,179	2,476
PROPERTY, PLANT AND EQUIPMENT	10,458	10,278
Less: Accumulated Depreciation and Amortization	(3,153)	(2,911)
Net Property, Plant and Equipment	7,305	7,367
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,777	1,701
Long-Term Investments	121	123
Goodwill	16	16
Other Intangibles	90	33
Other Special Funds	154	139
Derivative Contracts	9	72
Other	80	75
Total Noncurrent Assets	2,247	2,159
TOTAL ASSETS	$11,731	$12,002

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

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	June 30, 2014	December 31, 2013
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$44	$44
Accounts Payable	461	516
Derivative Contracts	88	76
Accrued Interest	27	28
Other	193	136
Total Current Liabilities	813	800
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,046	2,031
Asset Retirement Obligations	411	400
Other Postretirement Benefit (OPEB) Costs	212	206
Derivative Contracts	36	31
Accrued Pension Costs	35	35
Long-Term Accrued Taxes	88	53
Other	72	91
Total Noncurrent Liabilities	2,900	2,847
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	2,498	2,497
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,336	4,693
Accumulated Other Comprehensive Loss	(44)	(63)
Total Member's Equity	5,520	5,858
TOTAL LIABILITIES AND MEMBER'S EQUITY	$11,731	$12,002

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

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

	Six Months Ended June 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$218	$351
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	144	133
Amortization of Nuclear Fuel	98	95
Provision for Deferred Income Taxes and ITC	(22)	74
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	297	20
Non-Cash Employee Benefit Plan Costs	7	33
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(59)	(47)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	132	97
Margin Deposit	(234)	(8)
Accounts Receivable	16	24
Accounts Payable	(72)	(91)
Accounts Receivable/Payable—Affiliated Companies, net	229	213
Other Current Assets and Liabilities	13	(8)
Employee Benefit Plan Funding and Related Payments	(3)	(44)
Other	50	24
Net Cash Provided By (Used In) Operating Activities	814	866
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(226)	(248)
Proceeds from Sales of Available-for-Sale Securities	563	625
Investments in Available-for-Sale Securities	(577)	(637)
Short-Term Loan—Affiliated Company, net	50	179
Other	(46)	—
Net Cash Provided By (Used In) Investing Activities	(236)	(81)
CASH FLOWS FROM FINANCING ACTIVITIES		
Redemption of Long-Term Debt	—	(300)
Cash Dividend Paid	(575)	(510)
Contributed Capital	—	24
Other	(3)	(2)
Net Cash Provided By (Used In) Financing Activities	(578)	(788)
Net Increase (Decrease) in Cash and Cash Equivalents	—	(3)
Cash and Cash Equivalents at Beginning of Period	6	7
Cash and Cash Equivalents at End of Period	$6	$4
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$47	$60
Interest Paid, Net of Amounts Capitalized	$62	$55

Accrued Property, Plant and Equipment Expenditures	$48	$46

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
OPERATING REVENUES	$1,435	$1,423	$3,580	$3,418
OPERATING EXPENSES				
Energy Costs	565	580	1,610	1,547
Operation and Maintenance	362	369	824	796
Depreciation and Amortization	217	207	444	422
Taxes Other Than Income Taxes	—	14	—	35
Total Operating Expenses	1,144	1,170	2,878	2,800
OPERATING INCOME	291	253	702	618
Other Income	14	15	28	28
Other Deductions	(1)	(1)	(1)	(2)
Interest Expense	(67)	(75)	(135)	(148)
INCOME BEFORE INCOME TAXES	237	192	594	496
Income Tax Expense	(86)	(71)	(229)	(196)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$151	$121	$365	$300

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
NET INCOME	$151	$121	$365	$300
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 for the three and six months ended 2014 and 2013	—	(1)	—	(1)
COMPREHENSIVE INCOME	$151	$120	$365	$299

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

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

	June 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$257	$18
Accounts Receivable, net of allowances of $58 and $56 in 2014 and 2013, respectively	846	832
Unbilled Revenues	238	300
Materials and Supplies	126	115
Prepayments	186	24
Regulatory Assets	229	243
Derivative Contracts	2	25
Deferred Income Taxes	18	16
Other	7	12
Total Current Assets	1,909	1,585
PROPERTY, PLANT AND EQUIPMENT	19,889	19,071
Less: Accumulated Depreciation and Amortization	(5,048)	(4,964)
Net Property, Plant and Equipment	14,841	14,107
NONCURRENT ASSETS		
Regulatory Assets	2,584	2,612
Regulatory Assets of VIEs	355	476
Long-Term Investments	360	361
Other Special Funds	374	354
Derivative Contracts	20	69
Restricted Cash of VIEs	24	24
Other	146	132
Total Noncurrent Assets	3,863	4,028
TOTAL ASSETS	$20,613	$19,720

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

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

	June 30, 2014	December 31, 2013
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$800	$500
Securitization Debt of VIEs Due Within One Year	251	237
Commercial Paper and Loans	—	60
Accounts Payable	491	535
Accounts Payable—Affiliated Companies, net	93	190
Accrued Interest	67	67
Clean Energy Program	200	142
Deferred Income Taxes	—	30
Obligation to Return Cash Collateral	122	119
Regulatory Liabilities	176	43
Other	287	314
Total Current Liabilities	2,487	2,237
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,522	4,406
Other Postretirement Benefit (OPEB) Costs	814	839
Accrued Pension Costs	26	27
Regulatory Liabilities	169	233
Regulatory Liabilities of VIEs	11	11
Clean Energy Program	27	—
Environmental Costs	330	363
Asset Retirement Obligations	282	274
Long-Term Accrued Taxes	63	72
Other	58	47
Total Noncurrent Liabilities	6,302	6,272
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	5,264	5,066
Securitization Debt of VIEs	134	259
Total Long-Term Debt	5,398	5,325
STOCKHOLDER’S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2014 and 2013—132,450,344 shares	892	892
Contributed Capital	695	520
Basis Adjustment	986	986
Retained Earnings	3,852	3,487
Accumulated Other Comprehensive Income	1	1
Total Stockholder’s Equity	6,426	5,886
Total Capitalization	11,824	11,211

TOTAL LIABILITIES AND CAPITALIZATION	$20,613	$19,720

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

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

	Six Months Ended June 30,	
	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$365	$300
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	444	422
Provision for Deferred Income Taxes and ITC	73	75
Non-Cash Employee Benefit Plan Costs	13	78
Cost of Removal	(50)	(46)
Change in Accrued Storm Costs	(3)	(81)
Net Change in Other Regulatory Assets and Liabilities	192	62
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	44	6
Materials and Supplies	(11)	(6)
Prepayments	(162)	(192)
Accounts Payable	16	47
Accounts Receivable/Payable—Affiliated Companies, net	(98)	(137)
Other Current Assets and Liabilities	(31)	8
Employee Benefit Plan Funding and Related Payments	(44)	(134)
Other	(11)	19
Net Cash Provided By (Used In) Operating Activities	737	421
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(996)	(1,148)
Proceeds from Sales of Available-for-Sale Securities	8	32
Investments in Available-for-Sale Securities	(6)	(13)
Solar Loan Investments	(1)	(15)
Net Cash Provided By (Used In) Investing Activities	(995)	(1,144)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	(60)	(106)
Issuance of Long-Term Debt	500	900
Redemption of Long-Term Debt	—	(150)
Redemption of Securitization Debt	(111)	(106)
Contributed Capital	175	100
Other	(7)	(12)
Net Cash Provided By (Used In) Financing Activities	497	626
Net Increase (Decrease) In Cash and Cash Equivalents	239	(97)
Cash and Cash Equivalents at Beginning of Period	18	116
Cash and Cash Equivalents at End of Period	$257	$19
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$102	$110

Interest Paid, Net of Amounts Capitalized	$127	$135
Accrued Property, Plant and Equipment Expenditures	$192	$189

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

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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 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 its 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 an operating 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 in New Jersey, which are regulated by the BPU.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which, effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a twelve-year Amended and Restated Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain 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, 2013 and Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

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. 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, 2013.

On December 31, 2013, Energy Holdings distributed the outstanding equity of its 50% interest in a partnership that owns and operates a generation facility in Hawaii and its wholly owned interest in PSEG Solar Source LLC to PSEG. PSEG in turn contributed this distribution to Power as an additional equity investment. This transaction was accounted for as a non-cash transfer of equity interest between entities under common control with prior period financial statements for Power retrospectively adjusted to include the earnings related to the transfer. As a result, Power’s Operating Revenues increased $3 million and $7 million for the three months and six months ended June 30, 2013, respectively, and Power's Net Income increased $6 million and $10 million for the three months and six months ended June 30, 2013, respectively.

Note 2. Recent Accounting Standards
New Standards Adopted during 2014
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, the unrecognized tax benefit will be presented on the Balance Sheet as a liability and will not be combined with deferred tax assets in cases where that tax benefit cannot or will not, if permissible, be used to settle any additional income taxes that would result from the disallowance of a tax position.
The standard was effective for fiscal years and interim periods beginning after December 15, 2013. The impact of adopting this standard is immaterial.
New Standards Issued But Not Yet Adopted
Revenue from Contracts with Customers
This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.
The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.
The update is effective for annual and interim reporting periods beginning after December 15, 2016. Early application is not permitted. We are currently analyzing the impact of this standard on our financial statements.
Presentation of Financial Statements and Property, Plant and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity
This accounting standard was issued to change the criteria for reporting discontinued operations. The standard requires that a component of an entity be reported in discontinued operations if the disposal represents a strategic shift that has, or will have, a major effect on the entity’s operations and financial results, including a disposal of a major geographical area, a major line of business, a major equity method investment, or other major parts of an entity.
The amendment should be applied prospectively for all disposals of an entity that occur within interim and annual periods beginning on or after December 15, 2014; and all businesses that, on acquisition, are classified as held for sale that occur within interim and annual periods beginning on or after December 15, 2014. We will evaluate all future disposals under the new guidance beginning on January 1, 2015.
Transfers and Servicing - Repurchase-to-Maturity Transactions, Repurchase-Financings and Disclosures
This standard changes the accounting for repurchase-to-maturity transactions and linked repurchase-financings to secured borrowing accounting, which is consistent with the accounting for other repurchase agreements. It also requires disclosures for repurchase agreements, securities lending transactions, and repurchase-to-maturity transactions that are accounted for as secured borrowings.
This standard is effective for the first interim or annual period beginning after December 15, 2014.
We are currently analyzing this standard but do not expect its impact to be material 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

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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 Transition Funding and Transition Funding II are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the assets of these VIEs 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.

PSE&G’s maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of June 30, 2014 and December 31, 2013. 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 2014 or in 2013. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

Variable Interest Entity for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco’s operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI’s annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

PSEG recognized a long-term receivable primarily related to future funding by LIPA of Servco’s recognized pension and other postretirement benefit (OPEB) liabilities. This receivable is presented separately on the Condensed Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted. See Note 7. Pension and Other Postretirement Benefits for additional information.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Condensed Consolidated Statement of Operations.

Note 4. 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, 2013.

- Remediation Adjustment Charge (RAC)—On April 18, 2014, PSE&G filed a petition with the BPU requesting recovery of $66 million related to RAC 21 net manufactured gas plant expenditures through July 31, 2013. This matter is pending.
- Weather Normalization Clause (WNC)—In April 2014, the BPU approved PSE&G's filing with respect to deficiency revenues from the 2012-2013 Winter Period. The BPU’s approval of a final WNC resulted in no change to the provisional rate previously approved by the BPU and implemented effective October 1, 2013, which was set to recover $26 million from customers during the 2013-2014 Winter Period (October 1, 2013 through May 31, 2014).

On July 1, 2014, PSE&G filed a petition with the BPU seeking approval to refund $45 million in revenues to its customers during the 2014-2015 Winter Period as a result of excess revenues collected during the colder than normal 2013-2014 Winter Period. This matter is pending.

- Basic Gas Supply Service (BGSS)—In January and February 2014, PSE&G filed self-implementing one-month BGSS residential customer bill credits with the BPU for 25 cents per therm for the months of February and March

2014. These credits provided approximately $93 million in total credits to residential customers, reducing the BGSS deferred balance. On April 1, 2014, the BGSS rate reverted back to the current rate.
In May, 2014, PSE&G made its Annual BGSS filing with the BPU requesting a reduction of $112 million in annual BGSS revenues. If approved, the BGSS rate would be reduced from approximately 54 cents to 45 cents per therm effective October 1, 2014.

- Capital Stimulus Infrastructure Programs (CIP II)—In June 2014, the BPU approved PSE&G's petition to recover annual revenue requirements of approximately $28 million for program costs incurred for its CIP II investments through September 30, 2013, which represents the final phase of the program. Base rates were adjusted effective July 1, 2014 to reflect the recovery.
- Societal Benefits Charge (SBC) and Non-Utility Generation Charge (NGC)—In May 2014, the BPU approved PSE&G's petition to recover actual SBC and NGC costs incurred through December 31, 2013 under its Energy Efficiency & Renewable Energy Programs, Social Programs and NGC. New rates were implemented on June 1, 2014 to recover approximately $400 million over the succeeding 12 months.
- Solar and Energy Efficiency-Green Program Recovery Charges (GPRC)—In June 2014, PSE&G filed a petition with the BPU requesting recovery of costs and investments in the combined eight components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. The rates proposed in our filing are designed to recover $111 million and $18 million in electric and gas revenues, respectively, on an annual basis. This matter is pending.

Note 5. 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 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, 2014	As of December 31, 2013
	Millions	
Commercial/Industrial	$193	$192
Residential	14	15
Total	$207	$207

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.

The following table shows Energy Holdings’ gross and net lease investment as of June 30, 2014 and December 31, 2013, respectively.

	As of June 30, 2014	As of December 31, 2013
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$699	$701
Estimated Residual Value of Leased Assets	529	529
Unearned and Deferred Income	(397)	(405)
Gross Investment in Leases	831	825
Deferred Tax Liabilities	(688)	(727)
Net Investment in Leases	$143	$98

The corresponding receivables associated with the lease portfolio are reflected in the following table, 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 commercial real estate properties.

Counterparties’ Credit Rating (Standard & Poor's (S&P)) As of June 30, 2014	Lease Receivables, Net of Non-Recourse Debt As of June 30, 2014
	Millions
AA	$19
AA-	56
BBB+ - BB+	316
BB-	134
B	165
Not Rated	9
Total	$699

The “BB-” and the "B" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of June 30, 2014, the gross investment in the leases of such assets, net of non-recourse debt, was $563 million ($30 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 (UNAUDITED)

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	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$84	64	%	1,044	Coal	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$117	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	$111	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, the 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).

Although all lease payments 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.

GenOn REMA, LLC, an indirect subsidiary of NRG Energy, Inc. (NRG) notified PJM that it no longer intends to place the coal-fired units at the Shawville generating facility in long-term protective layup. Instead, those units will be shut down temporarily beginning in April 2015, with an expected return to service no later than June 2016 using an alternative fuel.

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. These facilities are leased to Midwest Generation (MWG), which was an indirect subsidiary of Edison Mission Energy (EME). In December 2012, EME and MWG filed for relief under Chapter 11 of the U.S. Bankruptcy Code. In October 2013, NRG, EME, MWG, Nesbitt and other creditor parties involved in the bankruptcy executed a new agreement under which NRG would acquire substantially all of EME's assets, including the Powerton and Joliet leased assets. In March 2014, the Bankruptcy Court approved the transaction. As part of the transaction, (i) the leases for the Powerton and Joliet coal units were assumed on their existing terms, (ii) all past due rent under the leases was paid in full, (iii) NRG assumed EME's tax indemnity and guarantee obligations, and (iv) NRG agreed to invest up to $350 million in the Powerton and Joliet coal units so they can be operated in compliance with environmental regulations. On April 1, 2014, NRG and

EME closed on the transaction in accordance with these terms, bringing the lease payments current.

Note 6. 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 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.

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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, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$644	$294	$(2)	$936
Debt Securities				
Government Obligations	434	6	(3)	437
Other Debt Securities	328	12	(1)	339
Total Debt Securities	762	18	(4)	776
Other Securities	65	—	—	65
Total NDT Available-for-Sale Securities	$1,471	$312	$(6)	$1,777

	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$609	$290	$(2)	$897
Debt Securities				
Government Obligations	438	3	(12)	429
Other Debt Securities	285	10	(4)	291
Total Debt Securities	723	13	(16)	720
Other Securities	84	—	—	84
Total NDT Available-for-Sale Securities	$1,416	$303	$(18)	$1,701

The 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.

	As of June 30, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$40	$39
Accounts Payable	$42	$36

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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, 2014				As of December 31, 2013			
	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)	$49	$(2)	$—	$—	$30	$(2)	$2	$—
Debt Securities								
Government Obligations (B)	86	(2)	33	(1)	300	(11)	1	(1)
Other Debt Securities (C)	58	(1)	8	—	107	(4)	3	—
Total Debt Securities	144	(3)	41	(1)	407	(15)	4	(1)
NDT Available-for-Sale Securities	$193	$(5)	$41	$(1)	$437	$(17)	$6	$(1)

(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, 2014.

(B) Debt Securities (Government)—Unrealized losses on Power’s NDT investments in United States Treasury obligations and Federal Agency mortgage-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, 2014.

(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, 2014.

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,	
	2014	2013	2014	2013
	Millions			
Proceeds from NDT Fund Sales	$313	$376	$558	$617
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	33	23	56	60
Gross Realized Losses	(5)	(6)	(9)	(25)
Net Realized Gains (Losses) on NDT Fund	$28	$17	$47	$35

Gross realized gains and gross realized losses disclosed in the preceding 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 $152 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power’s Condensed Consolidated Balance Sheets as of June 30, 2014.

The NDT available-for-sale debt securities held as of June 30, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$19
1 - 5 years	224
6 - 10 years	200
11 - 15 years	60
16 - 20 years	42
Over 20 years	231
Total NDT Available-for-Sale Debt Securities	$776

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). For the six months ended June 30, 2014, 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 a “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.

	As of June 30, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$12	$9	$—	$21
Debt Securities				
Government Obligations	113	1	(1)	113
Other Debt Securities	49	2	—	51
Total Debt Securities	162	3	(1)	164
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	$177	$12	$(1)	$188

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	As of December 31, 2013			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$14	$9	$—	$23
Debt Securities				
Government Obligations	109	—	(2)	107
Other Debt Securities	46	1	(1)	46
Total Debt Securities	155	1	(3)	153
Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	$172	$10	$(3)	$179

The 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, 2014	As of December 31, 2013
	Millions	
Accounts Receivable	$4	$1
Accounts Payable	$4	$2

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

	As of June 30, 2014				As of December 31, 2013			
	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)	$—	$—	$—	$—	$—	$—	$—	$—
Debt Securities								
Government Obligations (B)	2	—	29	(1)	47	(2)	2	—
Other Debt Securities (C)	2	—	7	—	18	(1)	1	—
Total Debt Securities	4	—	36	(1)	65	(3)	3	—
Rabbi Trust Available-for-Sale Securities	$4	$—	$36	$(1)	$65	$(3)	$3	$—

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund are through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG’s Rabbi Trust investments in United States Treasury obligations and Federal Agency mortgage-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 PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of June 30, 2014.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of June 30, 2014.

The proceeds from the sales of and the net realized gains (losses) on securities in the Rabbi Trust Fund were:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	Millions			
Proceeds from Rabbi Trust Sales	$14	$47	$26	$64
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$—	$4	$2	$4
Gross Realized Losses	(1)	(3)	(1)	(3)
Net Realized Gains (Losses) on Rabbi Trust	$(1)	$1	$1	$1

Net unrealized gains of $6 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of June 30, 2014. The Rabbi Trust available-for-sale debt securities held as of June 30, 2014 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$2
1 - 5 years	64
6 - 10 years	28
11 - 15 years	8
16 - 20 years	5
Over 20 years	57
Total Rabbi Trust Available-for-Sale Debt Securities	$164

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, 2014	As of December 31, 2013
	Millions	
Power	$44	$39
PSE&G	40	42
Other	104	98
Total Rabbi Trust Available-for-Sale Securities	$188	$179

Note 7. 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, except for Servco, are detailed as follows:

	Pension Benefits		OPEB		Pension Benefits		OPEB	
	Three Months Ended		Three Months Ended		Six Months Ended		Six Months Ended	
	June 30,		June 30,		June 30,		June 30,	
	2014	2013	2014	2013	2014	2013	2014	2013
	Millions							
Components of Net Periodic Benefit Cost								
Service Cost	$26	$29	$4	$5	$52	$58	$9	$10
Interest Cost	59	53	17	16	118	107	34	32
Expected Return on Plan Assets	(100)	(87)	(6)	(5)	(200)	(174)	(13)	(10)
Amortization of Net Prior Service Cost (Credit)	(4)	(4)	(3)	(3)	(9)	(9)	(7)	(7)
Actuarial Loss	14	47	6	10	28	94	12	21
Total Benefit Costs	$(5)	$38	$18	$23	$(11)	$76	$35	$46

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Pension and OPEB costs for Power, PSE&G and PSEG’s other subsidiaries, except for Servco, 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,	
	2014	2013	2014	2013	2014	2013	2014	2013
	Millions							
Power	$(1)	$11	$5	$5	$(3)	$22	$10	$11
PSE&G	(5)	22	12	17	(10)	45	23	33
Other	1	5	1	1	2	9	2	2
Total Benefit Costs	$(5)	$38	$18	$23	$(11)	$76	$35	$46

PSEG does not anticipate making contributions into its pension plan during 2014. However, during the three months ended March 31, 2014, PSEG contributed its entire planned contribution for the year 2014 of $14 million into its postretirement healthcare plan.

Servco Pension and OPEB

At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities (VIEs). These obligations, as well as the offsetting long-term receivable, are separately presented on the Condensed Consolidated Balance Sheet of PSEG.

Servco amounts are not included in any of the preceding pension and OPEB benefit cost disclosures. Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for the three months and six months ended June 30, 2014 were $23 million and $46 million, respectively. Servco plans to contribute an additional $21 million to its pension plan trusts during 2014. There were no OPEB-related revenues earned or costs incurred for the three months and six months ended June 30, 2014.

Note 8. 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

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- 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.

The face value of Power's outstanding guarantees, current exposure and margin positions as of June 30, 2014 and December 31, 2013 are shown as follows:

	As of June 30, 2014	As of December 31, 2013
	Millions	
Face Value of Outstanding Guarantees	$1,830	$1,639
Exposure under Current Guarantees	$218	$246
Letters of Credit Margin Posted	$176	$132
Letters of Credit Margin Received	$17	$25
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$—	$—
Counterparty Cash Margin Received	$(18)	$—
Net Broker Balance Deposited (Received)	$332	$80
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$760	$691
Liquidity Available under PSEG’s and Power’s Credit Facilities to Post Collateral	$3,478	$3,522
Additional Amounts Posted:		
Other Letters of Credit	$45	$45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. 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, Moody’s and Fitch ratings, many of these agreements allow the counterparty to demand further performance assurance. See preceding table.

The SEC and the Commodity Futures Trading Commission (CFTC) continue efforts to implement new rules to effect stricter regulation over swaps and derivatives, including imposing reporting and record-keeping requirements. In August 2013, PSEG began reporting its swap transactions to a CFTC-approved swap data repository. PSEG continues to monitor developments in this area, as the CFTC considers additional requirements such as a new position limits rule for physical commodity futures contracts and swaps that are economically equivalent to those contracts.

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

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 in violation of various statutes as discussed as follows.

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

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the Passaic River from Newark to Clifton, New Jersey is a “Super Fund” site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA has determined the need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of 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.

Seventy-three Potentially Responsible Parties (PRPs), including Power and PSE&G, agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (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 66 members, is presently conducting the RI/FS. The approximate seven percent allocation of the RI/FS costs currently attributable to PSE&G’s former MGP sites and approximate one percent attributable to Power’s generating stations are non-binding as it relates to the ultimate sharing of the remediation costs. Power has provided notice to insurers concerning this potential claim. The RI/FS is expected to be completed by the end of 2014 at an estimated cost of approximately $134 million. Of the estimated $134 million, as of December 31, 2013, the CPG Group had spent approximately $113 million, of which PSEG's total share had been approximately $7 million.

On April 11, 2014, the EPA released its revised “Focused Feasibility Study” (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the Passaic River’s lower eight miles under various alternatives ranging in costs from $365 million to $3.25 billion. The EPA's preferred alternative would involve dredging the river bank to bank and installing an engineered cap at an estimated cost of $1.7 billion. The draft FFS is subject to a public comment period, the EPA’s response, a design phase and at least five years for completion of the work. The work contemplated by the draft FFS is not subject to the cost sharing agreement discussed above.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (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. Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G.

At the EPA's direction, the CPG, with the exception of Tierra and Maxus, which are no longer members, has commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG’s share of the cost of that effort is approximately three percent.

Based on the EPA estimates above, Power and PSE&G believe that their respective ultimate shares of the costs to clean up the Passaic River will be immaterial, but are unable to predict the ultimate outcome of this matter.

New Jersey Spill Compensation and Control Act (Spill Act)

In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of a certain PRP’s discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. 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 are alleged to have owned, operated or contributed to a total of 11 sites or facilities that impacted these water bodies. The third party complaints sought statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. In December 2013, the Court approved a settlement of the entire third party action. Power and PSE&G's contributions to the settlement, either individually or in the aggregate, were immaterial.

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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 (the Passaic River federal trustees) 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. PSE&G is unable to estimate its portion of the possible loss or range of loss related to this matter.

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 August 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. 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 PSEG has not consented 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 $410 million and $486 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $410 million as of June 30, 2014. Of this amount, $89 million was recorded in Other Current Liabilities and $321 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $410 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 the 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 (D.C. Court), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 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 D.C. Court in support of the EPA's implementation of MATS. On April 15, 2014, the D.C. Court denied all petitions for review of the existing source NESHAP. Several parties, including 21 states have filed petitions for review with the U.S. Supreme Court.

Power believes that it will not be necessary to install any material controls at its New Jersey facilities. Additional controls are being installed at Power’s Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, to comply with the MACT regulations, the co-owners group, including Power, agreed to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction systems at Power’s jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be operational in the first quarter of 2015. Power's share of this investment is approximately $110 million.

Nitrogen Oxide (NO_X) Regulation

In 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) by May 30, 2015. Retirement notifications for the combustion turbines have been submitted to PJM Interconnection L.L.C. (PJM). PJM was notified that the Salem Unit 3 combustion turbine will no longer be available as a capacity resource and will be transitioned to an emergency generator for site use only. Based upon Power’s recently-completed evaluations of its steam electric generation units, an immaterial investment will be required to consistently reduce NO_x emissions below required limits beginning on May 1, 2015.

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 New Jersey Department of Environmental Protection 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 February 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.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. Following the effective date of the rule, each state will implement the provisions of the rule when considering the renewal of permits for existing facilities on a case by case basis.

State permitting decisions 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. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power’s forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

In October 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court in New Jersey seeking to compel the NJDEP to take action on Power's pending application for permit renewal at Salem either by denying the application or issuing a draft for public comments. At the NJDEP's request, the case was transferred to the Appellate Division on December 16, 2013. Power is unable to predict the outcome of this proceeding.

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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.

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

	Auction Year				
	2011	2012	2013	2014	
36-Month Terms Ending	May 2014	May 2015	May 2016	May 2017	(A)
Load (MW)	2,800	2,900	2,800	2,800	
$ per kWh	0.09430	0.08388	0.09218	0.09739	

(A) Prices set in the 2014 BGS auction became effective on June 1, 2014 when the 2011 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 17. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2018 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 nuclear fuel 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 2017 and a significant portion through 2018 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.

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As of June 30, 2014, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2018
	Millions
Nuclear Fuel	
Uranium	$467
Enrichment	$403
Fabrication	$167
Natural Gas	$970
Coal	$389

Regulatory Proceedings

FERC Compliance

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. PSEG notified the FERC, PJM and the PJM Independent Market Monitor (IMM) of this issue. During the three months ended March 31, 2014, Power recorded a charge to income in the amount of $25 million related to these findings for these past errors based upon its best estimate available at the time. PSEG cannot provide any assurances that the total liability associated with this matter will not increase or decrease over the amount recorded.

Upon discovery of the errors, PSEG retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. PSEG informed the FERC, PJM and the IMM of these additional issues, and has corrected these errors. Power is also in the process of implementing procedures to help mitigate the risk of similar issues occurring in the future.

The data required to calculate the full impact of the pricing errors is proprietary to PJM and PSEG does not have access to that information. In addition, PSEG does not have access to PJM's proprietary data to determine if the differences in quantity had any impact, and if so, the level of that impact. PSEG continues to conduct its investigation and is working with PJM and the IMM to determine the impact of the errors. The FERC has the authority to investigate the matter, which could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with these matters, or the applicability of mitigating factors. It is possible that Power will incur additional losses, and that such losses may be material, but PSEG cannot at the current time estimate the amount or range of any additional losses.

New Jersey Clean Energy Program

In June 2014, the BPU established the funding level for fiscal year 2015 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2015 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a current liability of $200 million and a noncurrent liability of $27 million as of June 30, 2014 for its outstanding share of the fiscal year 2015 and remaining fiscal year 2014 funding, respectively. 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).

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D 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 had incurred $79 million and $85 million of storm-related expense in 2013 and 2012, respectively, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized in O&M Expense, offset by $25 million and $19 million of insurance recoveries in 2013 and 2012, respectively.

Power incurred an additional $10 million and $19 million for the three months and six months ended June 30, 2014, primarily for repairs at certain generating stations in Power's fossil fleet.

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. As previously reported, PSEG is seeking recovery from its insurers for the property damage resulting from Superstorm Sandy, above its self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge. In that lawsuit, PSEG stated that its estimate of the total costs related to damaged facilities was approximately $426 million. Of these costs, $364 million and $62 million related to Power and PSE&G, respectively. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the Complaint. Discovery is ongoing. In April 2014, PSEG notified the insurance carriers of a revised estimate of $579 million for total costs related to damaged facilities, of which $484 million and $95 million related to Power and PSE&G, respectively. We cannot predict the outcome of this proceeding.

Note 9. Changes in Capitalization

The following capital transactions occurred in the six months ended June 30, 2014:

Power

- paid cash dividends of $575 million to PSEG.

PSE&G

- issued $250 million of 1.80% Secured Medium-Term Notes, Series I due June 2019,
- issued $250 million of 4.00% Secured Medium-Term Notes, Series I due June 2044,
- paid $105 million of Transition Funding's securitization debt,
- paid $6 million of Transition Funding II's securitization debt, and
- received a $175 million capital contribution from PSEG.

Note 10. 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 with changes in fair value recorded in the Consolidated Statements of Operations. 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.

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,
- the price of fuel to meet its fuel purchase requirements, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

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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, since 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, 2014 and December 31, 2013, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of June 30, 2014	As of December 31, 2013
	Millions	
Fair Value of Cash Flow Hedges	$2	$(4)
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$2	$(1)

The expiration date of the longest-dated cash flow hedge at Power is in March 2015. Power’s remaining $2 million of after-tax unrealized gains on these derivatives is expected to be reclassified to earnings during the next 12 months. There was no ineffectiveness associated with qualifying hedges as of June 30, 2014.

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 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. These natural gas contracts qualify as derivatives and are marked to fair market 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.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of June 30, 2014, 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, 2014 and December 31, 2013, the fair value of all the underlying hedges was $32 million and $38 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 as of June 30, 2014 and December 31, 2013.

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. 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, 2014						
	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	$2	$613	$(560)	$55	$2	$16	$73
Noncurrent Assets	—	158	(149)	9	20	16	45
Total Mark-to-Market Derivative Assets	$2	$771	$(709)	$64	$22	$32	$118
Derivative Contracts							
Current Liabilities	$—	$(799)	$711	$(88)	$—	$—	$(88)
Noncurrent Liabilities	—	(189)	153	(36)	—	—	(36)
Total Mark-to-Market Derivative (Liabilities)	$—	$(988)	$864	$(124)	$—	$—	$(124)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$2	$(217)	$155	$(60)	$22	$32	$(6)

	As of December 31, 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	$—	$323	$(266)	$57	$25	$16	$98
Noncurrent Assets	—	155	(83)	72	69	22	163
Total Mark-to-Market Derivative Assets	$—	$478	$(349)	$129	$94	$38	$261

Derivative Contracts							
Current Liabilities	$(4)	$(343)	$271	$(76)	$—	$—	$(76)
Noncurrent Liabilities	—	(111)	80	(31)	—	—	(31)
Total Mark-to-Market Derivative (Liabilities)	$(4)	$(454)	$351	$(107)	$—	$—	$(107)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$(4)	$24	$2	$22	$94	$38	$154

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(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, 2014 and December 31, 2013. 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 Condensed Consolidated Balance Sheet. As of June 30, 2014 and December 31, 2013, net cash collateral (received) paid of $155 million and $2 million, respectively, were netted against the corresponding net derivative contract positions. Of the $155 million as of June 30, 2014, $(2) million and $(4) million of cash collateral was netted against current assets and noncurrent assets, respectively, and $153 million and $8 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $2 million as of December 31, 2013, cash collateral of $(3) million and $5 million were netted against noncurrent 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 the 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 $116 million and $91 million as of June 30, 2014 and December 31, 2013, respectively. As of June 30, 2014 and December 31, 2013, Power had the contractual right of offset of $37 million and $39 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 $79 million and $52 million as of June 30, 2014 and December 31, 2013, 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 $760 million and $691 million as of June 30, 2014 and December 31, 2013, respectively, discussed in Note 8. 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, 2014 and 2013.

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,	
	2014	2013		2014	2013		2014	2013
	Millions							
PSEG								
Energy-Related Contracts	$1	$—	Operating Revenues	$—	$2	Operating Revenues	$—	$—
Interest Rate Swaps	—	—	Interest Expense	—	(1)		—	—
Total PSEG	$1	$—		$—	$1		$—	$—
Power								
Energy-Related Contracts	$1	$—	Operating Revenues	$—	$2	Operating Revenues	$—	$—
Total Power	$1	$—		$—	$2		$—	$—

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, 2014 and 2013.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Six 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) Six 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) Six Months Ended June 30,	
	2014	2013		2014	2013		2014	2013
	Millions							
PSEG								
	$(7)	$—	Operating Revenues	$(12)	$8	Operating Revenues	$—	$—

Energy-Related Contracts									
Interest Rate Swaps	—		—	Interest Expense	—		(1)		—	—
Total PSEG Power	$(7	)	$—		$(12)		$7		$—	$—
Energy-Related Contracts	$(7	)	$—	Operating Revenues	$(12)		$8	Operating Revenues	$—	$—
Total Power	$(7	)	$—		$(12)		$8		$—	$—

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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, 2013	$(4)	$(2)
Loss Recognized in AOCI	(8)	(5)
Loss Reclassified into Income	12	7
Balance as of March 31, 2014	$—	$—
Gain Recognized in AOCI	1	1
Loss Reclassified into Income	—	—
Balance as of June 30, 2014	$1	$1

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, 2014 and 2013.

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,	
		2014	2013	2014	2013
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$(58)	$163	$(852)	$(46)
Energy-Related Contracts	Energy Costs	(36)	(5)	77	53
Total PSEG and Power		$(94)	$158	$(775)	$7

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 months and $10 million for each of the six months ended June 30, 2014 and 2013, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of June 30, 2014 and December 31, 2013.

Type	Notional	Total Millions	PSEG	Power	PSE&G
As of June 30, 2014					
Natural Gas	Dth	513	—	386	127
Electricity	MWh	325	—	325	—
Financial Transmission Rights (FTRs)	MWh	27	—	27	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2013					
Natural Gas	Dth	614	—	466	148
Electricity	MWh	243	—	243	—
FTRs	MWh	16	—	16	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—

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, 2014, 92% 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).

The following table provides information on Power's credit risk from others, net of cash collateral, as of June 30, 2014. 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	$75	$14	$75	2	$48	(A)
Non-Investment Grade—External Rating	—	—	—	—	—	
Investment Grade—No External Rating	1	—	1	—	—	
Non-Investment Grade—No External Rating	7	—	7	—	—	
Total	$83	$14	$83	2	$48	

(A) Includes net exposure of $18 million with PSE&G. The remaining net exposure of $30 million is with a nonaffiliated power purchaser which is a regulated investment grade counterparty.

The net exposure listed in the preceding table, 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, 2014, Power had 153 active counterparties.

Note 11. 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, 2014, these consisted primarily of certain electric load contracts and long-term gas supply 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, 2014 and December 31, 2013, 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, 2014				
Description	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$501	$—	$501	$—	$—
Derivative Contracts:					
Energy-Related Contracts (B)	$86	$(709)	$—	$772	$23
Interest Rate Swaps (C)	$32	$—	$—	$32	$—
NDT Fund (D)					
Equity Securities	$936	$—	$929	$7	$—
Debt Securities—Govt Obligations	$437	$—	$—	$437	$—
Debt Securities—Other	$339	$—	$—	$339	$—
Other Securities	$64	$—	$63	$1	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$21	$—	$21	$—	$—
Debt Securities—Govt Obligations	$113	$—	$—	$113	$—
Debt Securities—Other	$51	$—	$—	$51	$—
Other Securities	$3	$—	$—	$3	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(124)	$864	$—	$(978)	$(10)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$64	$(709)	$—	$772	$1
NDT Fund (D)					
Equity Securities	$936	$—	$929	$7	$—
Debt Securities—Govt Obligations	$437	$—	$—	$437	$—
Debt Securities—Other	$339	$—	$—	$339	$—
Other Securities	$64	$—	$63	$1	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—
Debt Securities—Govt Obligations	$26	$—	$—	$26	$—
Debt Securities—Other	$12	$—	$—	$12	$—
Other Securities	$1	$—	$—	$1	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(124)	$864	$—	$(978)	$(10)
PSE&G					
Assets:					
Cash Equivalents (A)	$224	$—	$224	$—	$—

Derivative Contracts:					
Energy-Related Contracts (B)	$22	$—	$—	$—	$22
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$4	$—	$4	$—	$—
Debt Securities—Govt Obligations	$25	$—	$—	$25	$—
Debt Securities—Other	$11	$—	$—	$11	$—
Other Securities	$—	$—	$—	$—	$—

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	Recurring Fair Value Measurements as of December 31, 2013				
Description	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$439	$—	$439	$—	$—
Derivative Contracts:					
Energy-Related Contracts (B)	$223	$(349)	$—	$474	$98
Interest Rate Swaps (C)	$38	$—	$—	$38	$—
NDT Fund (D)					
Equity Securities	$897	$—	$892	$5	$—
Debt Securities—Govt Obligations	$429	$—	$—	$429	$—
Debt Securities—Other	$291	$—	$—	$291	$—
Other Securities	$84	$—	$57	$27	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$23	$—	$23	$—	$—
Debt Securities—Govt Obligations	$107	$—	$—	$107	$—
Debt Securities—Other	$46	$—	$—	$46	$—
Other Securities	$3	$—	$—	$3	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(107)	$351	$—	$(448)	$(10)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$129	$(349)	$—	$474	$4
NDT Fund (D)					
Equity Securities	$897	$—	$892	$5	$—
Debt Securities—Govt Obligations	$429	$—	$—	$429	$—
Debt Securities—Other	$291	$—	$—	$291	$—
Other Securities	$84	$—	$57	$27	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—
Debt Securities—Govt Obligations	$23	$—	$—	$23	$—
Debt Securities—Other	$10	$—	$—	$10	$—
Other Securities	$1	$—	$—	$1	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(107)	$351	$—	$(448)	$(10)
PSE&G					
Assets:					
Derivative Contracts:					

Energy Related Contracts (B)	$94	$—	$—	$—	$94
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—
Debt Securities—Govt Obligations	$25	$—	$—	$25	$—
Debt Securities—Other	$11	$—	$—	$11	$—
Other Securities	$1	$—	$—	$1	$—

(A) Represents money market mutual funds.

(B) 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. 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.

(C) 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.

(D) The fair value measurement table excludes cash of $1 million which is part of the NDT Fund. 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. Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active markets. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

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. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(E) 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 Condensed Consolidated Balance Sheet. As of June 30, 2014, net cash collateral (received) paid of $155 million, was netted against the corresponding net derivative contract positions. Of the $155 million as of June 30, 2014, $(6) million of cash collateral was netted against assets, and $161 million was netted against liabilities. As of December 31, 2013, net cash collateral (received) paid of $2 million, was netted against the corresponding net derivative contract positions. Of the $2 million as of December 31, 2013, $(3) million of cash collateral was netted against assets, and $5 million was netted against liabilities.

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 non-performance risk were not material to the financial statements.

For Power, in general, electric swaps are measured at fair value based on at least two pricing inputs, the underlying price of electricity at a liquid reference point and the basis difference between electricity prices at the liquid reference point and electricity prices at the respective delivery locations. 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. The fair value of certain of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. 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, natural gas supply contracts are measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The following tables provide details surrounding significant Level 3 valuations as of June 30, 2014 and December 31, 2013.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of June 30, 2014 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$—	$(10)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (A)	1	—			
Total Power		$1	$(10)			
PSE&G						
Gas	Forward Contracts	$22	$—	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		$22	$—			
Total PSEG		$23	$(10)			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2013 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$3	$(1)	Discounted Cash Flow	Power Basis	$0 to $10/MWh
Electricity	Electric Load Contracts	—	(8)	Discounted Cash Flow	Historic Load Variability	-5% to +10%
Other	Various (B)	1	(1)			
Total Power		$4	$(10)			
PSE&G						

Gas	Forward Contracts	$94	$—	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		$94	$—			
Total PSEG		$98	$(10)			

(A) Includes gas supply positions and long-term electric capacity positions which were immaterial as of June 30, 2014.
(B) Includes gas supply positions which were immaterial as of December 31, 2013.

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 is a seller, an increase in either the power basis or the load variability or the longer-term gas basis amounts would decrease the fair value. For gas supply contracts where PSE&G is a seller, an increase in gas transportation cost 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, 2014 and June 30, 2013, respectively, follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Three Months and Six Months Ended June 30, 2014

	Three Months Ended June 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2014	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2014
	Millions						
PSEG Net Derivative Assets (Liabilities)	$1	$6	$ 10	$—	$(1)	$(3)	$13
Power Net Derivative Assets (Liabilities)	$(11)	$6	$ —	$—	$(1)	$(3)	$(9)
PSE&G Net Derivative Assets (Liabilities)	$12	$—	$ 10	$—	$—	$—	$22

	Six Months Ended June 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2014	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of June 30, 2014
	Millions						
PSEG Net Derivative Assets (Liabilities)	$88	$(58)	$ (72)	$—	$58	$(3)	$13
Power Net Derivative Assets	$(6)	$(58)	$ —	$—	$58	$(3)	$(9)

(Liabilities)								
PSE&G Net Derivative Assets (Liabilities)	$94	$—	$	(72	)	$—	$—	$—	$22

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

	Three Months Ended June 30, 2013						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of April 1, 2013	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
	Millions						
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)

	Six Months Ended June 30, 2013						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2013	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
	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)

(A) PSEG’s and Power’s gains and losses attributable to changes in net derivative assets and liabilities include $6 million and $(58) million in Operating Income for the three months and six months ended June 30, 2014, respectively. The $6 million in Operating Income is unrealized. Of the $(58) million in Operating Income, $1 million is unrealized.

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

(C) Represents $(1) million and $58 million in settlements for the three months and six months ended June 30, 2014. Includes $10 million in settlements for the six months ended June 30, 2013.

(D) During the three months and six months ended June 30, 2014, $(3) million of net derivatives assets/liabilities were transferred from Level 3 to Level 2 due to more observable pricing for the underlying securities. During the three months 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 transfers were recognized as of the beginning of the quarters in which the transfers first occurred, as per PSEG's policy.

As of June 30, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $13 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

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.

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, 2014 and December 31, 2013.

	As of June 30, 2014		As of December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$20	$32	$24	$38
Power -Recourse Debt (B)	2,542	2,929	2,541	2,846
PSE&G (B)	6,064	6,465	5,566	5,629
Transition Funding (PSE&G) (B)	371	391	476	511
Transition Funding II (PSE&G) (B)	14	15	20	21
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	16	16	16	16
Total Long-Term Debt	$9,027	$9,848	$8,643	$9,061

(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.

Note 12. Other Income and Deductions

Other Income	Power Millions	PSE&G	Other (A)	Consolidated
Three Months Ended June 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$46	$—	$—	$46
Allowance for Funds Used During Construction	—	7	—	7
Solar Loan Interest	—	6	—	6
Other	—	1	2	3
Total Other Income	$46	$14	$2	$62
Three Months Ended June 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$33	$—	$—	$33
Allowance for Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	5	—	5
Other	2	4	2	8
Total Other Income	$35	$15	$2	$52
Six Months Ended June 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$78	$—	$—	$78
Allowance for Funds Used During Construction	—	13	—	13
Solar Loan Interest	—	12	—	12
Other	1	3	3	7
Total Other Income	$79	$28	$3	$110
Six Months Ended June 30, 2013				
NDT Fund Gains, Interest, Dividend and Other Income	$80	$—	$—	$80
Allowance for Funds Used During Construction	—	12	—	12
Solar Loan Interest	—	11	—	11
Other	2	5	3	10
Total Other Income	$82	$28	$3	$113

Other Deductions	Power	PSE&G	Other (A)	Consolidated
	Millions			
Three Months Ended June 30, 2014				
NDT Fund Realized Losses and Expenses	$8	$—	$—	$8
Other	1	1	—	2
Total Other Deductions	$9	$1	$—	$10
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
Six Months Ended June 30, 2014				
NDT Fund Realized Losses and Expenses	$14	$—	$—	$14
Other	5	1	2	8
Total Other Deductions	$19	$1	$2	$22
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

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

Note 13. Income Taxes

PSEG’s, Power’s and PSE&G’s effective tax rates for the three months and six months ended June 30, 2014 and 2013 were as follows:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
PSEG	34.8	%	39.6	%	38.4	%	40.1	%
Power	28.9	%	39.9	%	37.8	%	39.6	%
PSE&G	36.5	%	37.2	%	38.6	%	39.6	%

For the three months and six months ended June 30, 2014, as compared to the same periods in the prior year, the decrease in PSEG's and Power's effective tax rates were due primarily to Power's manufacturing deduction under Section 199 of the Internal Revenue Code.

PSEG's federal tax returns for the years 2007 through 2010 are currently being audited by the IRS. The audit is reasonably expected to be completed within the next 12 months.

In September 2013, the U.S. Department of the Treasury and the IRS released final regulations effective in 2014 that provide guidance on applying Section 263(a) of the IRC to amounts paid to acquire, produce, or improve tangible property, as well as rules for materials and supplies. Implementation of these regulations did not have any material impact on PSEG’s and its subsidiaries’ results of operations, financial condition or cash flows.

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. The American Taxpayer Relief Act of 2012 further extended the 50% bonus depreciation for qualified property placed into service before January 1, 2014. In addition, long production property placed into service in 2014 is eligible for 50% bonus depreciation for tax purposes. These provisions have generated cash for PSEG through tax benefits related to the accelerated depreciation. These tax benefits otherwise would have been received over an estimated average 20 year period.

Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

PSEG	Other Comprehensive Income (Loss) Three Months Ended June 30, 2014			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of March 31, 2014	$—	$(234)	$147	$(87)
Other Comprehensive Income before Reclassifications	1	—	23	24
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	2	(12)	(10)
Net Current Period Other Comprehensive Income (Loss)	1	2	11	14
Balance as of June 30, 2014	$1	$(232)	$158	$(73)

	Other Comprehensive Income (Loss) Three Months Ended June 30, 2013			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	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)

	Other Comprehensive Income (Loss) Six Months Ended June 30, 2014			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2013	$(2)	$(238)	$145	$(95)
Other Comprehensive Income before Reclassifications	(4)	—	34	30
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	6	(21)	(8)
Net Current Period Other Comprehensive Income (Loss)	3	6	13	22

Balance as of June 30, 2014	$1	$(232)	$158	$(73)

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2013 Cash Flow Hedges	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)

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Power

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of March 31, 2014	$—	$(201)	$144	$(57)
Other Comprehensive Income before Reclassifications	2	—	21	23
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	2	(12)	(10)
Net Current Period Other Comprehensive Income (Loss)	2	2	9	13
Balance as of June 30, 2014	$2	$(199)	$153	$(44)

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Three Months Ended June 30, 2013			
	Cash Flow Hedges	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)

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2014			
	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2013	$(1)	$(204)	$142	$(63)
Other Comprehensive Income before Reclassifications	(4)	—	31	27
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	7	5	(20)	(8)
Net Current Period Other Comprehensive Income (Loss)	3	5	11	19
Balance as of June 30, 2014	$2	$(199)	$153	$(44)

Accumulated Other Comprehensive Income (Loss)	Other Comprehensive Income (Loss) Six Months Ended June 30, 2013			Total

	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	
	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, 2014			Six Months Ended June 30, 2014		
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					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$—	$—	$—	$(12)	$5	$(7)
Interest Rate Swaps	Interest Expense	—	—	—	—	—	—
Total Cash Flow Hedges		—	—	—	(12)	5	(7)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	5	(2)	3
Amortization of Actuarial Loss	O&M Expense	(6)	2	(4)	(14)	5	(9)
Total Pension and OPEB Plans		(3)	1	(2)	(9)	3	(6)
Available-for-Sale Securities							
Realized Gains	Other Income	33	(17)	16	58	(30)	28
Realized Losses	Other Deductions	(6)	3	(3)	(10)	5	(5)
Other-Than-Temporary Impairments (OTTI)	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		25	(13)	12	44	(23)	21
Total		$22	$(12)	$10	$23	$(15)	$8

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					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$2	$(1)	$1	$8	$(3)	$5
Interest Rate Swaps	Interest Expense	(1)	—	(1)	(1)	—	(1)
Total Cash Flow Hedges		1	(1)	—	7	(3)	4
Pension and OPEB Plans							
	O&M Expense	1	—	1	5	(2)	3

Amortization of Prior Service (Cost) Credit							
Amortization of Actuarial Loss	O&M Expense	(17)	7	(10)	(38)	16	(22)
Total Pension and OPEB Plans		(16)	7	(9)	(33)	14	(19)
Available-for-Sale Securities							
Realized Gains	Other Income	2	(1)	1	4	(2)	2
OTTI	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		—	—	—	—	—	—
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, 2014			Six Months Ended June 30, 2014		
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					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$—	$—	$—	$(12)	$5	$(7)
Total Cash Flow Hedges		—	—	—	(12)	5	(7)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	2	(1)	1	4	(2)	2
Amortization of Actuarial Loss	O&M Expense	(6)	3	(3)	(12)	5	(7)
Total Pension and OPEB Plans		(4)	2	(2)	(8)	3	(5)
Available-for-Sale Securities							
Realized Gains	Other Income	33	(17)	16	56	(29)	27
Realized Losses	Other Deductions	(6)	3	(3)	(10)	5	(5)
OTTI	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		25	(13)	12	42	(22)	20
Total		$21	$(11)	$10	$22	$(14)	$8

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					
Cash Flow Hedges							
Energy-Related Contracts	Operating Revenues	$2	$(1)	$1	$8	$(3)	$5
Total Cash Flow Hedges		2	(1)	1	8	(3)	5
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	2	(1)	1	4	(2)	2
Amortization of Actuarial Loss	O&M Expense	(16)	7	(9)	(32)	13	(19)

Total Pension and OPEB Plans		(14)	6	(8)	(28)	11	(17)
Available-for-Sale Securities							
Realized Gains	Other Income	2	(1)	1	4	(2)	2
Realized Losses	Other Deductions	—	—	—	—	—	—
OTTI	OTTI	(2)	1	(1)	(4)	2	(2)
Total Available-for-Sale Securities		—	—	—	—	—	—
Total		$(12)	$5	$(7)	$(20)	$8	$(12)

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Note 15. 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 our 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,			
	2014		2013		2014		2013	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	$212	$212	$333	$333	$598	$598	$653	$653
EPS Denominator (Thousands)								
Weighted Average Common Shares Outstanding	505,875	505,875	505,900	505,900	505,976	505,976	505,921	505,921
Effect of Stock Based Compensation Awards	—	2,181	—	1,481	—	1,973	—	1,380
Total Shares	505,875	508,056	505,900	507,381	505,976	507,949	505,921	507,301
EPS								
Net Income	$0.42	$0.42	$0.66	$0.66	$1.18	$1.18	$1.29	$1.29

	Three Months Ended June 30,		Six Months Ended June 30,	
Dividend Payments on Common Stock	2014	2013	2014	2013
Per Share	$0.37	$0.36	$0.74	$0.72
In Millions	$187	$182	$374	$364

Note 16. Financial Information by Business Segments

	Power	PSE&G	Other (A)	Eliminations (B)		Consolidated
	Millions					
Three Months Ended June 30, 2014						
Total Operating Revenues	$986	$1,435	$131	$(303	)	$2,249
Net Income (Loss)	54	151	7	—		212
Gross Additions to Long-Lived Assets	100	515	5	—		620
Six Months Ended June 30, 2014						
Total Operating Revenues	$2,686	$3,580	$236	$(1,030	)	$5,472
Net Income (Loss)	218	365	15	—		598
Gross Additions to Long-Lived Assets	226	996	7	—		1,229
Three Months Ended June 30, 2013						
Total Operating Revenues	$1,193	$1,423	$14	$(320	)	$2,310
Net Income (Loss)	210	121	2	—		333
Gross Additions to Long-Lived Assets	97	576	9	—		682
Six Months Ended June 30, 2013						
Total Operating Revenues	$2,644	$3,418	$26	$(992	)	$5,096
Net Income (Loss)	351	300	2	—		653
Gross Additions to Long-Lived Assets	248	1,148	10	—		1,406
As of June 30, 2014						
Total Assets	$11,731	$20,613	$1,890	$(534	)	$33,700
Investments in Equity Method Subsidiaries	$121	$—	$3	$—		$124
As of December 31, 2013						
Total Assets	$12,002	$19,720	$4,025	$(3,225	)	$32,522
Investments in Equity Method Subsidiaries	$123	$—	$3	$—		$126

(A) Includes amounts applicable to Energy Holdings and PSEG LI, which are below the quantitative threshold for separate disclosure as reportable segments. Other also includes amounts applicable to PSEG (parent corporation) and Services.

(B) Intercompany eliminations, primarily related to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are 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 17. Related-Party Transactions.

Note 17. Related-Party Transactions
The following discussion relates to intercompany transactions, 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, 2014	2013	Six Months Ended June 30, 2014	2013
	Millions			
Revenue from Affiliates:				
Billings to PSE&G through BGS and BGSS Contracts (A)	$297	$320	$1,028	$991
Expense Billings from Affiliates:				
Administrative Billings from Services (B)	$(46)	$(43)	$(88)	$(88)

Related-Party Transactions	As of June 30, 2014	As of December 31, 2013
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$114	$267
Receivable from (Payable to) Services (B)	(25)	(31)
Receivable from (Payable to) PSEG (C)	13	97
Accounts Receivable (Payable)—Affiliated Companies, net	$102	$333
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	$740	$790
Working Capital Advances to Services (E)	$17	$17
Long-Term Accrued Taxes Receivable (Payable)	$(88)	$(53)

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

Related-Party Transactions	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
	Millions			
Expense Billings from Affiliates:				
Billings from Power through BGS and BGSS (A)	$(297)	$(320)	$(1,028)	$(991)
Administrative Billings from Services (B)	(64)	(62)	(124)	(123)
Total Expense Billings from Affiliates	$(361)	$(382)	$(1,152)	$(1,114)

 NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Related-Party Transactions	As of June 30, 2014	As of December 31, 2013
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$(114)	$(267)
Receivable from (Payable to) Services (B)	(53)	(73)
Receivable from (Payable to) PSEG (C)	74	150
Accounts Receivable (Payable)—Affiliated Companies, net	$(93)	$(190)
Working Capital Advances to Services (E)	$33	$33
Long-Term Accrued Taxes Receivable (Payable)	$(63)	$(72)

(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.

Note 18. 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, 2014					
Operating Revenues	$—	$972	$42	$(28)	$986
Operating Expenses	5	903	40	(29)	919
Operating Income (Loss)	(5)	69	2	1	67
Equity Earnings (Losses) of Subsidiaries	57	(3)	3	(54)	3
Other Income	8	47	—	(9)	46
Other Deductions	—	(8)	—	(1)	(9)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(27)	(6)	(5)	9	(29)
Income Tax Benefit (Expense)	21	(43)	—	—	(22)
Net Income (Loss)	$54	$54	$—	$(54)	$54
Comprehensive Income (Loss)	$67	$66	$—	$(66)	$67
Six Months Ended June 30, 2014					
Operating Revenues	$—	$2,656	$82	$(52)	$2,686
Operating Expenses	9	2,307	74	(53)	2,337
Operating Income (Loss)	(9)	349	8	1	349
Equity Earnings (Losses) of Subsidiaries	234	(3)	7	(231)	7
Other Income	16	80	—	(17)	79
Other Deductions	(4)	(14)	—	(1)	(19)
Other-Than-Temporary Impairments	—	(4)	—	—	(4)
Interest Expense	(55)	(13)	(10)	17	(61)
Income Tax Benefit (Expense)	36	(168)	(1)	—	(133)
Net Income (Loss)	$218	$227	$4	$(231)	$218
Comprehensive Income (Loss)	$237	$242	$4	$(246)	$237
Six Months Ended June 30, 2014					
Net Cash Provided By (Used In) Operating Activities	$292	$950	$32	$(460)	$814
Net Cash Provided By (Used In) Investing Activities	$138	$(415)	$(16)	$57	$(236)
Net Cash Provided By (Used In) Financing Activities	$(430)	$(534)	$(17)	$403	$(578)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
Three Months Ended June 30, 2013					
Operating Revenues	$—	$1,183	$37	$(27)	$1,193
Operating Expenses	2	835	32	(27)	842
Operating Income (Loss)	(2)	348	5	—	351
Equity Earnings (Losses) of Subsidiaries	219	(2)	5	(217)	5
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)	—	—	(140)
Net Income (Loss)	$210	$213	$4	$(217)	$210
Comprehensive Income (Loss)	$203	$198	$4	$(202)	$203
Six Months Ended June 30, 2013					
Operating Revenues	$—	$2,624	$74	$(54)	$2,644
Operating Expenses	4	2,035	65	(53)	2,051
Operating Income (Loss)	(4)	589	9	(1)	593
Equity Earnings (Losses) of Subsidiaries	372	(2)	8	(370)	8
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)	1	—	(231)
Net Income (Loss)	$351	$362	$8	$(370)	$351
Comprehensive Income (Loss)	$376	$370	$8	$(378)	$376
Six Months Ended June 30, 2013					
Net Cash Provided By (Used In) Operating Activities	$386	$884	$15	$(419)	$866
Net Cash Provided By (Used In) Investing Activities	$138	$(411)	$(26)	$218	$(81)
Net Cash Provided By (Used In) Financing Activities	$(524)	$(476)	$11	$201	$(788)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
As of June 30, 2014					
Current Assets	$4,186	$1,923	$109	$(4,039)	$2,179
Property, Plant and Equipment, net	79	6,065	1,161	—	7,305
Investment in Subsidiaries	4,426	121	—	(4,547)	—
Noncurrent Assets	322	1,923	136	(134)	2,247
Total Assets	$9,013	$10,032	$1,406	$(8,720)	$11,731
Current Liabilities	$647	$3,468	$737	$(4,039)	$813
Noncurrent Liabilities	348	2,340	346	(134)	2,900
Long-Term Debt	2,498	—	—	—	2,498
Member's Equity	5,520	4,224	323	(4,547)	5,520
Total Liabilities and Member's Equity	$9,013	$10,032	$1,406	$(8,720)	$11,731
As of December 31, 2013					
Current Assets	$4,413	$2,076	$102	$(4,115)	$2,476
Property, Plant and Equipment, net	81	6,108	1,178	—	7,367
Investment in Subsidiaries	4,645	124	—	(4,769)	—
Noncurrent Assets	222	1,847	138	(48)	2,159
Total Assets	$9,361	$10,155	$1,418	$(8,932)	$12,002
Current Liabilities	$697	$3,474	$745	$(4,116)	$800
Noncurrent Liabilities	309	2,247	338	(47)	2,847
Long-Term Debt	2,497	—	—	—	2,497
Member's Equity	5,858	4,434	335	(4,769)	5,858
Total Liabilities and Member's Equity	$9,361	$10,155	$1,418	$(8,932)	$12,002

Immaterial Correction of Prior Financial Information

The financial information included in the tables above has been corrected from the disclosure provided in Power's Form 10-Q filed on July 30, 2013 and Form 10-K filed on February 26, 2014 to conform to the requirements of Section 210.3-10 of SEC Regulation S-X.

In the prior disclosure, Operating Revenues and Operating Expenses among the Guarantor Subsidiaries were eliminated in the Consolidating Adjustments column. The revised presentation eliminates this activity in the Guarantor Subsidiaries column and removes such activity from the Consolidating Adjustments column. This decreased both Operating Revenues and Operating Expenses in both the Guarantor Subsidiaries and Consolidating Adjustments columns by $352 million and $714 million for the three months and six months ended June 30, 2013, respectively. This correction had no impact on Power’s consolidated Operating Revenues and Operating Expenses.

In addition, the revised information was corrected to present the intercompany balances on a net basis when the right of offset exists in either Current Assets or Current Liabilities. This resulted in the following increases (decreases) to certain categories of the condensed consolidated balance sheet as of December 31, 2013 as follows:

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Increase (Decrease)				
	Millions				
As of December 31, 2013					
Current Assets	$253	$(6,840)	$(842)	$7,429	$—
Investment in Subsidiaries	—	(605)	—	605	—
Total Assets	$253	$(7,445)	$(842)	$8,034	$—
Current Liabilities	$253	$(7,445)	$(237)	$7,429	$—
Member's Equity	—	—	(605)	605	—
Total Liabilities and Member's Equity	$253	$(7,445)	$(842)	$8,034	$—

These corrections to the presentation had no impact to Power’s condensed consolidated financial statements. These corrections to the presentation had no impact on any liquidity measures of Power. They did not alter the net increase or net decrease in cash for Power, the Guarantor Subsidiaries, or the Other Subsidiaries. There was no impact to Power's loan covenants as a result of these corrections. Management believes these corrections are immaterial.

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

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (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 two reportable segments, our principal direct wholly owned subsidiaries, which are:

- Power, our wholesale energy supply company that integrates its nuclear, fossil and renewable 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, and
- PSE&G, our public utility company which primarily provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business of our 2013 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. Risk Factors 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 2013 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2014 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 and the 2013 Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

OVERVIEW OF 2014 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D infrastructure projects with greater diversity of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to respond to market volatility and capitalize on opportunities as they arise in the locations in which we operate.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and six months ended June 30, 2014 and 2013 are presented as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
Earnings (Losses)	2014	2013	2014	2013
	Millions			
Power	$54	$210	$218	$351
PSE&G	151	121	365	300
Other (A)	7	2	15	2
PSEG Net Income	$212	$333	$598	$653
PSEG Net Income Per Share (Diluted)	$0.42	$0.66	$1.18	$1.29

(A) Other includes activities at the parent company, PSEG LI, and Energy Holdings as well as intercompany eliminations.

Power's results above include the realized gains, losses and earnings on the Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity and the 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 following table:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	Millions, after tax			
NDT Fund Income (Expense) (A)	$14	$8	$23	$17
Non-Trading MTM Gains (Losses)	$(42)	$80	$(174)	$(25)

(A) NDT Fund Income (Expense) 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, and impairments on certain NDT securities recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in O&M Expense, as well as the depreciation related to the ARO asset.

Our $121 million decrease in Net Income for the three months ended June 30, 2014 was driven by

- MTM losses in 2014 due to an increase in prices on forward positions as compared to gains in 2013,
- lower volumes of generation sold in the PJM region at lower average realized prices, and
- higher Operation and Maintenance (O&M) costs largely due to planned outages at our fossil plants, including maintenance and installation of upgraded technology at our Linden station, partly offset by lower pension and other postretirement benefit (OPEB) costs and cost control measures.

These decreases were partially offset by higher revenues due to increased investments in transmission projects.

Our $55 million decrease in Net Income for the six months ended June 30, 2014 was driven by

- higher O&M costs due to higher planned outage and maintenance costs at our fossil plants, including maintenance and installation of upgraded technology at our Linden plant, partly offset by lower pension and other postretirement benefit (OPEB) costs and cost control measures,
- higher MTM losses in 2014 resulting from an increase in prices on forward positions,
- lower volumes of electricity sold under our basic generation service (BGS) contracts resulting from serving fewer tranches in 2014, and
- higher generation costs due to higher fuel costs and higher gas costs related to the basic gas supply service (BGSS) contract.

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These decreases were partially offset by

- higher revenues due to increased investments in transmission projects.
- higher average realized prices on sales in the New England (NE) and PJM regions, as well as higher capacity revenues, primarily in PJM resulting from higher average auction prices, and
- higher sales volumes under the BGSS contract due to colder average temperatures in the 2014 winter heating season.

Power’s results also benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2014. Power manages these contracts for the benefit of PSE&G’s customers through the BGSS arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers’ needs is available, Power can use it to supply gas to its generating units in New Jersey and to make third party sales.

Under the PJM capacity auction conducted in May 2014, Power cleared 8,693 MW of its generating capacity at an average price of $164.61 MW-day for the 2017-2018 delivery period, a price consistent with what has been realized in the past three auctions. For a more detailed discussion on the Reliability Pricing Model (RPM) capacity auction, refer to Part II. Item 5. Other Information—Federal Regulation—Capacity Market Issues.

Power’s 2014 results were unfavorably impacted by an extended refueling outage at Salem Unit 2. A planned refueling outage began on April 12, 2014 but was extended due to repairs to the Reactor Coolant Pump Turning Vanes. Salem Unit 2 returned to service on July 14, 2014.

At PSE&G, our regulated utility, we continued to invest capital in T&D infrastructure projects aimed at maintaining the reliability of our service to our customers. PSE&G’s results for the first half of 2014 reflect the favorable impacts from these investments as well as a slowly improving economy. Effective January 1, 2014, PSE&G's annual formula rate increased our annual transmission revenues by approximately $171 million. Over the past few years, these types of investments have altered the business mix of PSEG’s overall results of operations to reflect a higher percentage contribution by PSE&G.

Regulatory, Legislative and Other Developments

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we closely 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.

We also advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. On May 19, 2014, the EPA released the final Clean Water Act Section 316(b) rule on cooling water intake that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. Eight of Power’s generating facilities and three of its jointly-owned generating facilities are subject to the rule. As adopted by the EPA, the rule requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts, primarily by reducing the amount of fish and shellfish that are impinged or entrained at a cooling water intake structure. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. However, the EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis, and will require facilities to conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. We are unable to predict the outcome that these permitting decisions may take and the effect, if any, that they may have on us although such impacts could be material. See Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities and Item 5. Other Information—Environmental Matters—Water Pollution Control for additional information.

On June 18, 2014, the EPA issued a proposed greenhouse gas emissions regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction. States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions. The EPA is requesting comment on many aspects of the proposal and therefore, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact of the regulation. For a more detailed discussion of this proposed regulation, see Item 5. Other Information—Environmental Matters—Climate Change.

In addition, Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented.

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The FERC's rule 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. However, the FERC's action presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM initiated a solicitation process pursuant to Order 1000 to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem Units 1 and 2 and Hope Creek nuclear generation facilities. In June 2014, PJM's management recommended approval by its Board of a 500 kV project to be constructed by PSE&G to address performance issues at Artificial Island. On July 23, 2014, the PJM Board announced that it was deferring the selection of a project to enable four developers, including PSE&G, to supplement their project proposals by, among other things, re-evaluating the costs of their respective proposals. PJM currently expects to select a project by the end of 2014.

In May 2014, a federal court issued a rule that vacated a FERC Order in which the FERC determined that demand response providers should receive full market compensation for power and held that the FERC has no jurisdiction over demand response. The implications of these decisions could be significant for the capacity market. See Item 5. Other Information—Federal Regulation—Capacity Market Issues—for additional information.

In recent years we have been impacted by severe weather conditions, including Hurricane Irene in 2011 and Superstorm Sandy in 2012, the latter storm resulting in the highest level of customer outages in our history. For more detailed information, refer to Item 1—Note 8. Commitments and Contingent Liabilities—Superstorm Sandy. As a result, we filed a petition in early 2013 with the New Jersey Board of Public Utilities (BPU) in which we recommended making investments in our gas and electric distribution systems to improve resiliency. In May 2014, the BPU approved the settlement of our Energy Strong Proposal in a total amount of $1.22 billion. The settlement provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction (AFUDC), through an accelerated recovery mechanism. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017. Work on the program, including some infrastructure replacement work and detailed engineering, has begun. We believe that the rate impacts of the Energy Strong program will be muted significantly as a result of scheduled reductions to customer bills that will be taking place over the next few years and the expectation that gas prices will remain low. For more detailed information, refer to Item 5. Other Information—Energy Strong Program.

On January 1, 2014, we commenced operation of the LIPA T&D system under a twelve-year contract with opportunity to extend for an additional eight years. Also, beginning in January 2015, Power will provide fuel procurement and power management services to LIPA under separate agreements.

In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. We notified the FERC, PJM and the PJM Independent Market Monitor (IMM) of this issue. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. We informed the FERC, PJM and the IMM of these additional issues, and have corrected these errors. Power is also in the process of implementing procedures to help mitigate the risk of similar issues occurring in the future. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with these matters, or the applicability of mitigating factors. For more detailed information regarding this matter, refer to Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities—FERC Compliance.

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 during the year as we remain diligent in managing costs. In the first six months of 2014, our

- total nuclear fleet achieved an average capacity factor of 90%, despite the extended outage at Salem Unit 2,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 26,600 GWh, while addressing unit outages and balancing fuel availability and price volatility, and

- construction of transmission and solar projects proceeded on schedule and within budget.

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Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during the first six months of 2014 as we

- had cash on hand of $570 million as of June 30, 2014,
- extended the expiration dates of PSEG's $500 million and Power's $1.6 billion five-year credit facilities from 2017 to 2019, and maintained substantial liquidity and solid investment grade credit ratings, including positive outlooks at S&P, and
- increased our indicated annual dividend for 2014 to $1.48 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, our Energy Strong program and other projects with internally generated cash and external debt financing.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and 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 the first six months of 2014 we

- placed into service our 230 kV Burlington-Camden and 230 kV North Central Reliability transmission projects,
- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs, and
- completed installation of equipment to increase output and improve efficiency at our Linden combined cycle gas generating plant and continue to plan for the installation of such equipment at our other combined cycle gas units.

In July 2014, we acquired rights to a 13 MW solar energy facility located near El Paso, Texas, which is expected to be operational in the fourth quarter of 2014 and a 3.6 MW solar energy facility located near Burlington, Vermont, which is expected to be operational late in the third quarter of 2014.

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 our Energy Strong program and other 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 the FERC of market design rules that continue to promote competition,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

For the remainder of 2014 and beyond, the key issues and challenges we expect our business to confront include

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer demand,

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- 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, and
- delays and other obstacles that might arise in connection with the construction of our T&D projects, including in connection with permitting and regulatory approvals.

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RESULTS OF OPERATIONS
PSEG
Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, Power and PSE&G, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Note 17. Related-Party Transactions.

	Three Months Ended June 30,		Increase/ (Decrease) 2014 vs. 2013		Six Months Ended June 30,		Increase/ (Decrease) 2014 vs. 2013	
	2014	2013			2014	2013		
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$2,249	$2,310	$(61)	(3)	$5,472	$5,096	$376	7
Energy Costs	789	755	34	5	2,145	1,910	235	12
Operation and Maintenance	800	646	154	24	1,656	1,356	300	22
Depreciation and Amortization	295	283	12	4	601	573	28	5
Taxes Other than Income Taxes	—	14	(14)	(100)	—	35	(35)	(100)
Income from Equity Method Investments	3	3	—	—	7	5	2	40
Other Income and (Deductions)	52	39	13	33	88	71	17	24
Other-Than-Temporary Impairments	2	2	—	—	4	4	—	—
Interest Expense	94	101	(7)	(7)	191	203	(12)	(6)
Income Tax Expense	112	218	(106)	(49)	372	438	(66)	(15)

The 2014 amounts in the preceding table for Operating Revenues and O&M Costs each include $111 million and $200 million for the three months and six months ended June 30, 2014, respectively, for Long Island Electric Utility Servco, LLC, a wholly owned subsidiary of PSEG LI. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Note 3. Variable Interest Entities for further explanation. The following discussions for Power and PSE&G provide a detailed explanation of their respective variances.
Power

	Three Months Ended June 30,		Increase/ (Decrease) 2014 vs. 2013		Six Months Ended June 30,		Increase/ (Decrease) 2014 vs. 2013	
	2014	2013			2014	2013		
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$986	$1,193	$(207)	(17)	$2,686	$2,644	$42	2
Energy Costs	520	495	25	5	1,564	1,355	209	15
Operation and Maintenance	327	280	47	17	629	563	66	12
Depreciation and Amortization	72	67	5	7	144	133	11	8
Income from Equity Method Investments	3	5	(2)	(40)	7	8	(1)	(13)
Other Income (Deductions)	37	25	12	48	60	44	16	36
Other-Than-Temporary Impairments	2	2	—	—	4	4	—	—

Interest Expense	29	29	—	—	61	59	2	3
Income Tax Expense	22	140	(118)	(84)	133	231	(98)	(42)

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Three Months Ended June 30, 2014 as Compared to 2013

Operating Revenues decreased $207 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $224 million due primarily to

- lower net revenues of $212 million due primarily to MTM losses in 2014 resulting from an increase in prices on forward positions as compared to MTM gains in 2013 and lower generation sold in the PJM region at lower average realized prices, and
- a decrease of $28 million due primarily to lower volumes of electricity sold under our BGS contracts as a result of serving fewer tranches in 2014,
- partially offset by a net increase of $16 million due primarily to higher capacity revenues resulting from higher average auction prices.

Gas Supply Revenues increased $14 million due primarily to

- a net increase of $20 million due to higher sales volumes at lower average natural gas prices to third party customers,
- partially offset by a net decrease of $6 million due to lower sales prices under the BGSS contract.

Other Operating Revenues increased $3 million due to transition fees related to the fuel management and power supply management contracts with LIPA.

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 $25 million due to

- Generation costs increased $27 million due primarily to higher congestion costs largely offset by lower net fuel costs, reflecting the utilization of lower volumes of natural gas at lower average prices and lower nuclear fuel costs.
- Gas costs decreased $2 million, reflecting lower average gas inventory costs on obligations under the BGSS contract, offset by higher sales volumes to third party customers at lower average prices in 2014.

Operation and Maintenance increased $47 million due primarily to

- higher planned outage costs of $32 million primarily at our Linden combined cycle gas generating plant, including maintenance and installation of upgraded technology,
- a net increase of $13 million due to a $25 million insurance reimbursement in June 2013 for Superstorm Sandy partially offset by lower storm costs in 2014, and
- a $4 million charge related to the New Jersey sales and use tax settlement in May 2014,
- partially offset by lower pension and OPEB expense of $12 million.

Depreciation and Amortization increased $5 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) increased $12 million primarily due to higher net realized gains related to the NDT Fund restructuring in May 2014.

Interest Expense experienced no material change.

Income Tax Expense decreased $118 million in 2014 due primarily to lower pre-tax income.

Six Months Ended June 30, 2014 as Compared to 2013

Operating Revenues increased $42 million due to changes in generation, gas supply and other operating revenues.

Gas Supply Revenues increased $108 million due primarily to

- a net increase of $72 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2014 winter heating season, and
- a net increase of $36 million due to higher sales volumes at lower average sales prices to third party customers.

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Generation Revenues decreased $73 million due primarily to

- lower net revenues of $96 million due primarily to higher MTM losses in 2014 resulting from an increase in prices on forward positions, partially offset by higher average realized prices in the PJM and NE regions,
- a decrease of $43 million due primarily to lower volumes of electricity sold under our BGS contracts as a result of serving fewer tranches in 2014, and
- a net decrease of $18 million due to lower volumes on wholesale load contracts in the PJM and NE regions,
- partially offset by a net increase of $84 million in PJM due primarily to higher capacity revenues resulting from higher average auction prices and higher ancillary revenue, partially offset by a decrease in operating reserve revenue.

Other Operating Revenues increased $7 million due to transition fees related to the fuel management and power supply management contracts with LIPA.

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 $209 million due to

- Generation costs increased $168 million due primarily to higher fuel costs, reflecting higher average realized natural gas prices, the unfavorable MTM impact from lower average unrealized natural gas prices on forward positions and the utilization of higher volumes of coal and oil. These increased costs were largely offset by $89 million of lower congestion costs in the PJM region.
- Gas costs increased $41 million, principally related to higher volumes sold under the BGSS contract and to third parties due to colder average temperatures during the 2014 winter heating season, partially offset by lower average gas inventory costs.

Operation and Maintenance increased $66 million due primarily to

- higher planned outage and maintenance costs of $86 million at our fossil plants, primarily at our Linden combined cycle gas generating plant, including maintenance and installation of upgraded technology, and
- higher nuclear outage and refueling costs of $8 million, primarily at our Salem facility,
- partially offset by lower pension and OPEB costs of $26 million, and
- a net decrease of $5 million due to a $25 million insurance reimbursement in June 2013, more than offset by lower storm costs of $30 million in 2014.

Depreciation and Amortization increased $11 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income and (Deductions) increased $16 million due primarily to losses that were incurred in March 2013 as a result of rebalancing the NDT portfolio.

Interest Expense experienced no material change.

Income Tax Expense decreased $98 million in 2014 due primarily to lower pre-tax income.

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PSE&G

	Three Months Ended June 30,		Increase/ (Decrease)		Six Months Ended June 30,		Increase/ (Decrease)	
	2014	2013	2014 vs. 2013		2014	2013	2014 vs. 2013	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$1,435	$1,423	$12	1	$3,580	$3,418	$162	5
Energy Costs	565	580	(15)	(3)	1,610	1,547	63	4
Operation and Maintenance	362	369	(7)	(2)	824	796	28	4
Depreciation and Amortization	217	207	10	5	444	422	22	5
Taxes Other Than Income Taxes	—	14	(14)	(100)	—	35	(35)	(100)
Other Income (Deductions)	13	14	(1)	(7)	27	26	1	4
Interest Expense	67	75	(8)	(11)	135	148	(13)	(9)
Income Tax Expense	86	71	15	21	229	196	33	17

Three Months Ended June 30, 2014 as Compared to 2013

Operating Revenues increased $12 million due to changes in delivery, commodity, clause, and other operating revenues.

Delivery Revenues increased $28 million due primarily to an increase in transmission revenues.

- Transmission revenues were $39 million higher due to net rate increases resulting primarily from increased capital investments.
- Electric distribution revenues decreased $9 million due primarily to lower TEFA revenue of $11 million due to elimination of the TEFA rate effective January 1, 2014 and lower sales volumes of $7 million, partially offset by higher revenue from Green Program Recovery Charges (GPRC) of $9 million.
- Gas distribution revenues decreased $2 million due primarily to lower Transitional Energy Facilities Assessment (TEFA) revenue of $3 million due to elimination of the TEFA rate effective January 1, 2014 and lower Capital Infrastructure Program (CIP) related revenue of $4 million, partially offset by $4 million from higher sales volumes.

Commodity Revenue decreased $15 million due to lower Electric revenues, partially offset by higher Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $31 million due primarily to $19 million in lower BGS revenues and $12 million in lower revenues from collection of Non-Utility Generation Charges (NGC) and sales of Non-Utility generation (NUG) energy due primarily to lower volume. BGS sales decreased 1% due primarily to weather.
- Gas revenues increased $16 million due primarily to higher BGSS volumes of $10 million and higher BGSS prices of $6 million.

Clause Revenues decreased $5 million due primarily to lower Societal Benefit Charges (SBC) of $4 million, and lower Securitization Transition Charge (STC) revenues of $4 million, partially offset by a higher Solar Pilot Recovery Charge (SPRC) of $3 million. The change in the SBC, STC and SPRC amounts were entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, STC or SPRC collections.

Other Operating Revenues increased $4 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Operating Expenses

Energy Costs decreased $15 million. This is entirely offset by Commodity Revenue.

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Electric costs decreased $31 million or 7% due primarily to $9 million of lower BGS and NUG prices and $21 million in lower BGS and NUG volumes. BGS and NUG volumes decreased 5% due primarily to customer migration to TPS and weather.

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- Gas costs increased $16 million or 13% due to $10 million or 8% in higher sales volumes and $6 million or 5% in higher prices.

Operation and Maintenance decreased $7 million, of which the most significant components were

- an $18 million decrease in pension and OPEB expenses,
- partially offset by a $6 million increase in costs related to clauses due primarily to higher GPRC of $15 million, partially offset by lower SBC and CIP of $9 million. Due to the nature of the GPRC, SBC and CIP clause mechanisms, these are entirely offset in revenues, and
- a $4 million increase in gas bad debt expense.

Depreciation and Amortization increased $10 million due primarily to

- a $12 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects,
- partially offset by a $4 million decrease in amortization of Regulatory Assets.

Taxes Other Than Income Taxes decreased $14 million due to elimination of the TEFA rate effective January 1, 2014.
Other Income and (Deductions) experienced no significant change.
Interest Expense decreased $8 million due primarily to a partial redemption of securitization debt and maturity of Medium-Term Notes (MTNs) in the second half of 2013, partially offset by the issuance of MTNs in the second half of 2013.
Income Tax Expense increased $15 million due primarily to higher pre-tax income.

Six Months Ended June 30, 2014 as Compared to 2013
Operating Revenues increased $162 million due to changes in delivery, commodity, clause, and other operating revenues.
Delivery Revenues increased $78 million due primarily to an increase in transmission revenues.

- Transmission revenues were $78 million higher due to net rate increases resulting primarily from increased capital investments.
- Gas distribution revenues increased $2 million due primarily to $52 million from higher sales volumes and higher revenue from GPRC of $6 million, partially offset by lower Weather Normalization Clause (WNC) revenue of $36 million due to colder than normal weather, lower TEFA revenue of $13 million due to elimination of the TEFA rate effective January 1, 2014 and lower CIP related revenues of $7 million.
- Electric distribution revenues decreased $2 million due primarily to lower TEFA revenue of $21 million due to elimination of the TEFA rate effective January 1, 2014 and lower sales volumes of $4 million, partially offset by higher revenue from GPRC of $24 million.

Commodity Revenue increased $63 million due to higher Electric and Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues increased $18 million due primarily to $32 million in higher volumes of BGS sales, partially offset by $14 million in lower revenues from collection of NGC and lower sales volumes of NUG energy. BGS sales increased 4% due primarily to weather.
- Gas revenues increased $45 million due primarily to higher BGSS volumes of $100 million, partially offset by lower BGSS prices of $55 million. The average price of natural gas was 8% lower in 2014.

Clause Revenues increased $10 million due primarily to higher SBC. The change in the SBC amount was entirely offset by the amortization of Regulatory Assets and related costs in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC collections.
Other Operating Revenues increased $11 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

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Operating Expenses

Energy Costs increased $63 million. This is entirely offset by Commodity Revenue.

- Electric costs increased $18 million or 2% due to $51 million of increased deferred cost recovery, partially offset by $32 million in lower BGS and NUG volumes and $1 million of lower BGS and NUG prices. BGS and NUG volumes decreased 4% due primarily to customer migration to TPS.
- Gas costs increased $45 million or 7% due to $100 million or 15% in higher sales volumes, partially offset by $55 million or 8% in lower prices.

Operation and Maintenance increased $28 million, of which the most significant components were

- a $39 million increase in costs related primarily to GPRC and SBC. Due to the nature of the GPRC and SBC clause mechanisms, these are entirely offset in revenues, and
- a $20 million increase in operational expenses due primarily to winter storm-related costs of $7 million, damage claims of $6 million, transmission related costs of $4 million and general wage increases of $3 million,
- partially offset by a $36 million decrease in pension and OPEB expenses.

Depreciation and Amortization increased $22 million due primarily to a $20 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects.

Taxes Other Than Income Taxes decreased $35 million due to elimination of the TEFA rate effective January 1, 2014.

Other Income and (Deductions) experienced no significant change.

Interest Expense decreased $13 million due primarily to a partial redemption of securitization debt and maturity of MTNs in the second half of 2013, partially offset by the issuance of MTNs in the latter part of 2013.

Income Tax Expense increased $33 million due primarily to higher pre-tax income.

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 two direct major operating subsidiaries.

Operating Cash Flows

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

For the six months ended June 30, 2014, our operating cash flow increased $105 million as compared to the same period in 2013. The net change was due primarily to higher federal tax payments made by the parent company in 2014 and the net changes from Power and PSE&G as discussed below.

Power

Power’s operating cash flow decreased $52 million from $866 million to $814 million for the six months ended June 30, 2014, as compared to the same period in 2013, primarily resulting from increased working capital needs, partially offset by a $41 million decrease in employee benefit plan funding. The increased working capital needs were primarily due to higher margin deposit requirements.

PSE&G

PSE&G’s operating cash flow increased $316 million from $421 million to $737 million for the six months ended June 30, 2014, as compared to the same period in 2013, due primarily to higher earnings, an increase in net regulatory liabilities related to BGS and NUG costs and over collections in Gas Weather Normalization Charges partly offset by GPRC rate recoveries and a $90 million decrease in employee benefit plan funding.

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 $4.3 billion credit facilities are provided by a diverse bank group. As of June 30, 2014, our total available credit capacity was $4.1 billion.

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As of June 30, 2014, no single institution represented more than 8% of the total commitments in our credit facilities.
As of June 30, 2014, 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 in the following table; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. In April 2014, PSEG and Power amended their 2012 credit agreements ending in 2017, extending the expiration date from March 2017 to April 2019. PSEG's $500 million and Power's $1.6 billion facility amendments, resulting in total commitments of $2.1 billion, will mature in 2019.
Our total credit facilities and available liquidity as of June 30, 2014 were as follows:

	As of June 30, 2014				
Company/Facility	Total Facility Millions	Usage	Available Liquidity	Expiration Date	Primary Purpose
PSEG					
5-year Credit Facility	$500	$8	$492	Apr 2019	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	$8	$992		
Power					
5-year Credit Facility	$1,600	$114	$1,486	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (B)	1,000	—	1,000	Mar 2018	Funding/Letters of Credit
Bilateral Credit Facility	100	100	—	Sept 2015	Letters of Credit
Total Power	$2,700	$214	$2,486		
PSE&G					
5-year Credit Facility (C)	$600	$13	$587	Mar 2018	CP Support/Funding/Letters of Credit
Total PSE&G	$600	$13	$587		
Total	$4,300	$235	$4,065		

(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.

Long-Term Debt Financing

PSE&G has $250 million of 5.00%, Series D, Medium Term Notes and $250 million of 0.85%, Series G, Medium Term Notes (MTNs) both maturing in August 2014 and $300 million of 2.70%, Series G, MTNs maturing in May 2015.
Power has a $44 million pollution control facilities loan servicing and securing a Pennsylvania Economic Development Financing Authority (PEDFA) bond due November 2042. The bond is backed by a three-year letter of credit that expires in November 2014. The PEDFA bond has been reclassified as debt due within the year.
For a discussion of our long-term debt transactions during 2014, see Note 9. Changes in Capitalization.

Common Stock Dividends

On July 15, 2014, our Board of Directors approved a $0.37 per share common stock dividend for the third quarter of 2014. This reflects an indicated annual dividend rate of $1.48 per share. 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 additional information related to cash dividends on our common stock, see Note 15. Earnings Per Share (EPS) and Dividends.

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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 January 2014, Moody's upgraded PSE&G's Mortgage Bond Rating from A1 to Aa3 and its commercial paper rating from P2 to P1. PSE&G's outlook is stable. In May 2014, Moody's published updated research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged.

In May 2014, S&P published updated research reports and revised the outlooks to positive from stable for the corporate credit and senior unsecured long-term ratings of PSEG, PSE&G and Power. S&P also affirmed the senior unsecured rating of BBB+ at Power and senior secured rating of A at PSE&G.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	Stable	Stable	Stable
Commercial Paper	P2	A2	F2
Power			
Outlook	Stable	Positive	Stable
Senior Notes	Baa1	BBB+	BBB+
PSE&G			
Outlook	Stable	Stable	Stable
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	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.

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. There were no material changes to our projected capital expenditures at Power and Services as compared to amounts disclosed in our 2013 Form 10-K. PSE&G has increased its total projected capital expenditures through 2016 by $295 million, including $145 million for additional transmission reliability enhancements in 2015 and $50 million and $100 million in 2015 and 2016, respectively, related to additional distribution expenditures for reliability enhancements and facility replacement.

On May 21, 2014, the BPU issued an Order approving our Energy Strong program, agreeing that PSE&G would spend $1.22 billion to protect and strengthen PSE&G's electric and gas systems against severe weather conditions over primarily a three-year period with some projects extending over five years. This amount is not included in the projected capital expenditures disclosed in our 2013 Form 10-K or in the increases reported above. See Item 5. Other Information—Energy Strong Program for additional information.

Power

During the six months ended June 30, 2014, Power made capital expenditures of $185 million, excluding $41 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, 2014, PSE&G made capital expenditures of $996 million, primarily for transmission and distribution system reliability. This does not include expenditures for certain energy efficiency and renewable programs of $13 million or cost of removal, net of salvage, of $50 million, which are included in operating cash flows.

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ACCOUNTING MATTERS

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

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.

From April to June, MTM VaR remained relatively stable with less volatile price movements. The range of VaR was narrower for the three months ended June 30, 2014 as compared with the year ended December 31, 2013.

	MTM VaR	
	Three Months Ended June 30, 2014	Year Ended December 31, 2013
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$20	$12
Average for the Period	$20	$15
High	$24	$29
Low	$16	$8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$31	$18
Average for the Period	$31	$23
High	$38	$46
Low	$25	$13

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

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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 2014 that have materially affected, or are reasonably likely to materially affect, each registrant’s internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS
We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3. of Part I of the 2013 Annual Report on Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

ITEM 1A. RISK FACTORS
There are no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2013 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 2014.

Three Months Ended June 30, 2014	Total Number of Shares Purchased	Average Price Paid per Share
April 1 - April 30	—	$—
May 1 - May 31	127,319	$39.37
June 1 - June 30	7,033	$38.93

ITEM 5. OTHER INFORMATION
Certain information reported in the 2013 Annual Report on Form 10-K and Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2013 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarter ended March 31, 2014. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.
Business Operations and Strategy
Other
December 31, 2013 Form 10-K page 13. On July 1, 2014, PSEG LI submitted a proposal to invest up to $200 million of capital in equipment at customer facilities that would improve energy efficiency and reduce peak load. PSEG LI proposed to make the investments from 2015 through 2018 and recover its investment and earn a return over approximately 10 years. The New York State Department of Public Service will review the proposal and make a recommendation to the LIPA Board which will decide whether to enter into a contract with PSEG LI.
Federal Regulation
FERC
Regulation of Wholesale Sales—Generation/Market Issues
Energy Clearing Prices
December 31, 2013 Form 10-K page 16 and March 31, 2014 Form 10-Q page 69. As a result of the polar vortex and related cold weather events in January 2014, there were both gas and electric price spikes in the Northeast markets, including in PJM. The FERC is currently examining the facts surrounding these price spikes, as well as "lessons learned" from the various Regional Transmission Operators/Independent System Operators (RTO/ISO) and potential changes in market rules intended to encourage dual fuel capability of generating units, the purchase of firm fuel to fire these units and the construction of additional natural gas pipeline capacity. In addition, PJM's Market Monitor has requested information from all market participants in PJM, including Power, looking at bidding behavior to rule out underlying market manipulation. The FERC has also gathered information but has not commenced an investigation.

We cannot predict what action, if any, the FERC may take.

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Capacity Market Issues

December 31, 2013 Form 10-K page 16 and March 31, 2014 Form 10-Q page 69. PJM, the New York ISO (NYISO), and the ISO-New England each have capacity markets that have been approved by the FERC. The FERC regulates these markets and continues to examine whether the market design for these three capacity markets is working optimally. One of the specific issues being considered by the FERC and addressed at an industry-wide technical conference in 2013 is whether capacity market rules are properly responding to, and fostering the development of, state public policies, demand response, fuel diversity and emerging technologies, as well as addressing concerns raised by future generation retirements. We cannot predict what action, if any, the FERC might take with regard to capacity market design. As noted below, one of the most significant developments, with the potential to impact all of the RTO/ISO capacity markets, is a May 2014 decision of the U.S. Court of Appeals for the D.C. Circuit (D.C. Court) holding that the FERC does not have jurisdiction over demand response. Capacity market rules continue to evolve on other fronts as well, including with respect to setting the demand curve for capacity and establishing new capacity zones. As discussed below, the ISO-NE, for example, recently established a downward sloping demand curve like the one in place in PJM that we believe should help to more appropriately incent the construction of new generation.

Capacity Market Issues—Demand Response

In May 2014, the D.C. Court issued a ruling vacating FERC Order No. 745, in which FERC determined that demand response providers should receive full Locational Marginal Pricing ("LMP") as compensation in energy markets. In so doing, the D.C. Court not only ruled that FERC's action in affording demand response providers full LMP was not just and reasonable; the D.C. Court further held that demand response itself is not within the FERC's jurisdiction. The implications of this decision on FERC-regulated energy and capacity markets, and demand response's future participation therein, could be significant and far-reaching. For example, if demand response is not able to participate in the capacity market in the future, or can participate but in a more limited or different fashion, this could in turn impact capacity prices. With respect to the D.C. Court's decision, several parties, including the FERC, PJM, the Maryland and Pennsylvania public utility commissions and various demand response providers, have filed petitions for rehearing before the full bench of judges of the D.C. Court. The effect of filing these petitions for rehearing is to stay the decision until after the D.C. Court rules on these petitions.

Capacity Market Issues—PJM

December 31, 2013 Form 10-K page 16 and March 31, 2014 Form 10-Q page 70. The FERC has issued orders (i) capping the amount of "limited" demand response resources (i.e. resources which can only be called on by PJM a limited number of times during the summer months) that can clear in PJM's capacity auctions, (ii) imposing requirements that these resources have "sell-offer" plans and accompanying officer certifications attesting to the resources' availability, and (iii) revising the operational requirements applicable to demand response, such as reducing the amount of advanced call time for such resources. We believe that capping "limited" demand response participation had an upward effect on capacity prices in the May 2014 auction. The FERC is also considering whether additional steps need to be taken to bar speculative sell offers from being submitted into PJM's capacity market auctions. In addition, the PJM Board has directed PJM management to develop a Performance Assurance proposal that includes both incentives and performance penalties to promote better generator performance during peak periods.

PJM has instituted a stakeholder proceeding to once again re-examine its rules for setting the Cost of New Entry (CONE), which in turn establishes the appropriate demand curve used in the capacity market auctions and affects capacity prices. This process is expected to result in a filing at the FERC to reset CONE for another three years beginning with the 2018/2019 delivery year.

Capacity Market Issues—Midwest Independent System Operator (MISO)

December 31, 2013 Form 10-K page 16 and March 31, 2014 Form 10-Q page 70. The import into PJM of significant amounts of MISO generation that is not subject to the same type of rules and requirements as generation that is located within PJM could adversely impact Power. The FERC issued an order permitting PJM to establish annual capacity import limits, which were then incorporated into the 2017/2018 planning parameters for the May 2014 base residual auction. We believe that these rules restricting capacity imports had an upward effect on prices in PJM in this auction.

Capacity Market Issues—ISO-New England (ISO-NE)

December 31, 2013 Form 10-K page 16. ISO-NE’s market for installed capacity in New England provides fixed capacity payments for generators, imports and demand response. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. In June 2014, the FERC issued an order requiring the implementation of a downward sloping demand curve, similar to the design in place in PJM, for use in ISO-NE's ninth capacity market auction to be held in February 2015 and effective in the 2018-2019 planning year. This action is expected to result in greater stability of capacity prices in New England and is also expected to send more appropriate price signals that

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will incent the development of new generation. One aspect of this order that PSEG has not supported is the exemption from the Minimum Offer Price Rule afforded annually up to 600 MW of renewable resources. We are challenging this portion of the order on rehearing on the grounds that we believe that it is unduly discriminatory and will suppress capacity prices.

On May 30, 2014, the FERC issued a decision on ISO-NE's and NEPOOL's respective Performance Incentives proposals which were submitted in order to help address resource performance problems in New England by incenting enhanced generator performance. The provisions consist of a two settlement structure in which capacity resources are paid both a base case capacity payment and a performance payment or charge during scarcity conditions. Further, the provisions do not recognize any exceptions from penalties for non-performance during scarcity conditions.

Capacity Market Issues—NYISO

December 31, 2013 Form 10-K page 17 and March 31, 2014 Form 10-Q page 70. NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Prior to 2013, the NYISO capacity model had recognized only two separate zones that potentially may separate in price: New York City and Long Island. In August 2013, the FERC issued an order approving a third capacity zone that will encompass the super zone that includes the lower Hudson Valley and New York City to take effect May 1, 2014.

In January 2014, the FERC issued an order accepting the NYISO's proposed reference unit (a generation unit with no environmental controls) that should be used for the purposes of establishing the CONE in the "rest of State" zone (excluding the lower Hudson Valley, New York City and Long Island), which may have the effect of depressing capacity prices. This order will set the demand curve on which future capacity prices paid to generators will be based for the period May 1, 2014 through April 30, 2017. That order was subsequently upheld by the FERC on rehearing in May 2014 and is now being challenged by the State of New York, the New York Public Service Commission and others in the federal appellate court.

Transmission Regulation—Transmission Policy Developments

December 31, 2013 Form 10-K page 17. The FERC concluded in Order No. 1000 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. PJM is currently implementing new rules under which the construction of certain types of transmission projects is no longer subject to a ROFR for incumbents. In May 2014, the FERC approved PJM's rules, which retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including projects being built on existing right-of-way and whose construction would interfere with incumbents' use of its right-of-way. Several companies, including PSE&G, have appealed various aspects of this approval order. The FERC has also approved the "state agreement approach" to cost allocation 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.

We cannot predict the final outcome or impact on us; however, specific implementation of Order 1000 in the various regions, including within our service territory, may expose us to competition from third party construction of certain transmission projects within our service territory while at the same time providing opportunities to build transmission outside of our service territory.

Transmission Regulation—Transmission Rate Proceedings

December 31, 2013 Form 10-K page 18 and March 31, 2014 Form 10-Q page 70. In December 2013, PSE&G was assigned construction responsibility by PJM of a new transmission project that will provide a double-circuit 345 kV line in the Bergen-Linden Corridor (BLC Project) to maintain reliability. Phases One through Three of the BLC Project are scheduled to be in service in 2016, 2017 and 2018, respectively, with certain components of Phase One required to be in service as early as June 2015. The estimated construction costs of the BLC Project are $1.2 billion. The net increase in PSE&G's capital expenditures is expected to be less than the estimated cost of the BLC Project, as it will eliminate the need for certain other projects that had been previously assigned by PJM. On March 28, 2014, we filed a petition with FERC seeking incentives for the BLC Project, specifically recovery of Construction Work in Progress in rate base and authorization to recover 100% of all prudently incurred development and construction costs if the BLC Project is abandoned or canceled, in whole or in part, for reasons beyond the control of PSE&G. In May 2014, the FERC issued an order granting our petition requesting incentives. A customer is currently challenging that order for reasons related to its allocated cost responsibility for the BLC project.

In September 2011, a complaint was filed by several state utility commissions and consumer advocates against transmission owners in New England challenging their base return on equity (ROE). In June 2014, the FERC issued an order in this proceeding that provided for a new approach for determining the ROE for public utilities that, among other things, is intended to narrow the parameters set in calculating the ROE. In applying the new methodology to this case, the FERC tentatively found that the New England transmission owners' base ROE should be reduced by 57 basis points, and instituted a hearing to allow the participants in the proceeding an opportunity to submit evidence in writing solely concerning the application of the new approach. In addition, the FERC directed that the approach to determine ROE set forth in the New England transmission owners order should apply to all currently pending ROE-related complaint cases in which the FERC has not issued a final order, which cases include the following:

- In February 2013, several state utility commissions and consumer advocates, including the BPU and the New Jersey Division of Rate Counsel, also filed a complaint at the FERC challenging the base ROE and formula transmission rate implementation protocols of transmission owners in Maryland, Pennsylvania, Delaware and New Jersey. This complaint remains pending;
- On November 12, 2013, a group of industrial customers in MISO filed a complaint against the MISO transmission owners, requesting that the FERC reduce the transmission owners' base ROE and eliminate the ROE adders for among other things, participation in an RTO. Alternatively, the customers requested that the FERC find the base ROE to be unjust and unreasonable and expeditiously establish settlement procedures; and
- On February 6, 2014, a public power association in New York filed a complaint against one of the New York transmission owners asking the FERC to reduce the ROE used to calculate the transmission owner's rates.

Various parties to the New England transmission owners' case noted above have filed motions for reconsideration and rehearing with the FERC, and on July 31, 2014, the state utility commissions and consumer advocates that originally challenged the New England transmission owners' base ROE filed another complaint at the FERC challenging ROE, allegedly based on new data, application of the newly-announced methodology, and materially changed market conditions. Like the September 2011 New England transmission owners' case, the results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

Compliance—FERC

March 31, 2014 Form 10-Q page 70. In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with these matters, or the applicability of mitigating factors. See Part I, Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities—FERC Compliance for further discussion of this matter.

Compliance—Reliability Standards

December 31, 2013 Form 10-K page 18 and March 31, 2014 Form 10-Q page 70. Congress has required the FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the United States electric transmission and generation system (grid) and to prevent major system blackouts. There has been considerable focus recently on physical security in light of, among other things, a substation attack in California that occurred in 2013. As a result, the FERC directed the NERC to draft a physical security standard intended to further protect assets deemed "critical" to reliability of the grid. The NERC submitted a draft standard to the FERC for its review and approval by the end of May 2014. The draft standard would require utilities to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. As part of these plans, utilities could decide to build additional redundancy into their systems. In July 2014, the FERC acted on the NERC submittal, proposing to modify the draft standard so that, among other things, governmental authorities such as FERC could add or subtract from a utility's list of critical substations. The FERC has sought public comment on its proposed modifications. Thus, the standard is not yet approved.

State Regulation

Energy Strong Program

December 31, 2013 Form 10-K page 20 and March 31, 2014 Form 10-Q page 71. On May 21, 2014, the BPU issued an Order approving the settlement of our Energy Strong program. The Energy Strong program encompasses infrastructure investments we will make to our BPU jurisdictional electric and gas system to improve resiliency for the future. Under the Order, PSE&G will invest $1.22 billion to (1) upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in

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the event of an electric outage, and (2) with respect to PSE&G's gas system, replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas; and upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones. The Order provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated AFUDC, and will occur for completed projects on a semi-annual (for electric investments) or annual (for gas investments) basis. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, to be filed no later than November 1, 2017.

Environmental Matters

Air Pollution Control

Cross-State Air Pollution Rule (CSAPR)

December 31, 2013 Form 10-K page 21 and March 31, 2014 Form 10-Q page 71. In July 2011, the EPA issued the final CSAPR, which limited power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x 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. In August 2012, the D.C. Court vacated CSAPR and ordered that the existing Clean Air Interstate Rule requirements remain in effect until an appropriate substitute rule has been promulgated. On April 29, 2014, the Supreme Court overturned the D.C. Court's ruling. On June 26, 2014, the EPA filed a motion to lift the stay on CSAPR and allow for implementation of Phase I to begin on January 1, 2015. The D.C. Court's decision is pending. We do not anticipate any material impact on our earnings or financial condition due to the CSAPR.

Climate Change

CO_2 Regulation Under the CAA

December 31, 2013 Form 10-K page 22. 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. On June 23, 2014, the U.S. Supreme Court ruled that the EPA has authority to regulate CO_2 emissions of stationary sources but that the EPA lacked the authority to issue the Tailoring Rule. The Supreme Court ruled that stationary sources are not required to obtain permits under the Clean Air Act rules regarding Prevention of Significant Deterioration (PSD) on the sole basis of their potential GHG emissions, but that GHG emissions must be considered for sources that are otherwise subject to PSD review.

On June 25, 2013, the President directed the EPA to 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.

On June 18, 2014, the EPA issued a proposed GHG regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of four components: (1) heat rate improvements at existing coal-fired power plants, (2) increased use of existing natural gas combined cycle capacity, (3) operation of zero-emitting generation (renewables and nuclear), and (4) increased use of demand-side energy efficiency. States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions. Comments are due October 16, 2014. The EPA is requesting comments on many aspects of the proposal and therefore, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact.

If relevant federal or state common law were to impose liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material. However, approximately 60% of our generation output comes from nuclear facilities which are GHG-free and would not be impacted.

Regional Greenhouse Gas Initiative (RGGI)

December 31, 2013 Form 10-K page 22 and March 31, 2014 Form 10-Q page 72. In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and

Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions. Generators may acquire allowances through a regional auction or through secondary markets.

New Jersey withdrew from RGGI beginning in 2012. As a result, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances. This action has been challenged by environmental groups in the New Jersey state court. On March 25, 2014, the Appellate Division of the New Jersey Superior Court ruled that the New Jersey Department of Environmental Protection (NJDEP) improperly withdrew its regulation under which RGGI had been implemented. The Court gave the NJDEP 60 days to initiate a public process to either repeal or amend that regulation to provide that it is applicable only when New Jersey is a participant in a regional or other established greenhouse gas program. On July 7, 2014, the NJDEP published its intent to formally repeal the rules implementing RGGI in New Jersey. We cannot predict the outcome of this matter.

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Water Pollution Control

Cooling Water Intake Structure Regulation

December 31, 2013 Form 10-K page 23 and March 31, 2014 Form 10-Q page 72. On May 19, 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA did not mandate closed cycle cooling as “Best Technology Available.” Instead, the EPA set a fish impingement mortality standard that relies on a technology-based approach. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. The rule also requires that entrainment BTA decisions rely on site-specific analysis that includes an assessment of social costs-social benefits.

The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications.

We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions 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 Part I, Item 1. Financial Statements—Note 8. Commitments and Contingent Liabilities—Clean Water Act Permit Renewals for additional information.

Fuel and Waste Disposal

Nuclear Fuel Disposal

December 31, 2013 Form 10-K page 24 and March 31, 2014 Form 10-Q page 72. 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 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In 2013, the federal court ordered the Secretary of the U.S. Department of Energy (DOE) to submit a proposal to Congress to adjust the fee to zero. In January 2014, the Secretary of the DOE comported with the court order and submitted the zero fee adjustment change letter to Congress, subject to DOE appeal rights. On May 9, 2014, the DOE served us with a letter stating that as of May 16, 2014, the Nuclear Waste fee was being suspended/reduced to zero. The elimination of this fee is expected to result in an annualized pre-tax benefit of approximately $30 million.

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ITEM 6. EXHIBITS
A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 10:	Key Executive Severance Plan, amended effective July 14, 2014
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
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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 10:	Key Executive Severance Plan, amended effective July 14, 2014
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
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c. PSE&G:

Exhibit 10:	Key Executive Severance Plan, amended effective July 14, 2014
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
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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: August 1, 2014

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PSEG POWER LLC
(Registrant)

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

Date: August 1, 2014

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

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

Date: August 1, 2014