PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-Q
October 30, 2015

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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 September 30, 2015
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
001-00973	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
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480

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.

Public Service Enterprise Group Incorporated	Large accelerated filer x	Accelerated filer o	Non-accelerated filer o	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
PSEG Power LLC	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 October 20, 2015, Public Service Enterprise Group Incorporated had outstanding 505,961,856 shares of its sole class of Common Stock, without par value.

As of October 20, 2015, 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.

Public Service Electric and Gas Company and PSEG Power LLC 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 are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in 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 regulations, including market structures and transmission planning,
- 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 for 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$2,688	$2,641	$8,137	$8,113
OPERATING EXPENSES				
Energy Costs	815	863	2,577	3,008
Operation and Maintenance	746	714	2,170	2,370
Depreciation and Amortization	313	318	960	919
Total Operating Expenses	1,874	1,895	5,707	6,297
OPERATING INCOME	814	746	2,430	1,816
Income from Equity Method Investments	3	3	10	10
Other Income	47	75	171	185
Other Deductions	(14)	(9)	(36)	(31)
Other-Than-Temporary Impairments	(30)	(10)	(45)	(14)
Interest Expense	(96)	(100)	(291)	(291)
INCOME BEFORE INCOME TAXES	724	705	2,239	1,675
Income Tax Expense	(285)	(261)	(869)	(633)
NET INCOME	$439	$444	$1,370	$1,042
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
BASIC	505	506	505	506
DILUTED	508	507	508	507
NET INCOME PER SHARE:				
BASIC	$0.87	$0.88	$2.71	$2.06
DILUTED	$0.87	$0.87	$2.70	$2.05
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$0.39	$0.37	$1.17	$1.11

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
NET INCOME	$439	$444	$1,370	$1,042
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $33, $33, $35 and $21 for the three and nine months ended 2015 and 2014, respectively	(31)	(30)	(32)	(17)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $(1), $6 and $(3) for the three and nine months ended 2015 and 2014, respectively	—	1	(9)	4
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(5), $(2), $(17) and $(5) for three and nine months ended 2015 and 2014, respectively	9	3	25	9
Other Comprehensive Income (Loss), net of tax	(22)	(26)	(16)	(4)
COMPREHENSIVE INCOME	$417	$418	$1,354	$1,038

See Notes to Condensed Consolidated Financial Statements.

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

	September 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$271	$402
Accounts Receivable, net of allowances of $59 and $52 in 2015 and 2014, respectively	1,199	1,254
Tax Receivable	5	211
Unbilled Revenues	203	284
Fuel	451	538
Materials and Supplies, net	472	484
Prepayments	180	108
Derivative Contracts	162	240
Deferred Income Taxes	23	11
Regulatory Assets	189	323
Regulatory Assets of Variable Interest Entities (VIEs)	—	249
Restricted Cash of VIEs	26	—
Other	23	15
Total Current Assets	3,204	4,119
PROPERTY, PLANT AND EQUIPMENT	34,625	32,196
Less: Accumulated Depreciation and Amortization	(9,020)	(8,607)
Net Property, Plant and Equipment	25,605	23,589
NONCURRENT ASSETS		
Regulatory Assets	3,161	3,192
Long-Term Investments	1,235	1,307
Nuclear Decommissioning Trust (NDT) Fund	1,715	1,780
Long-Term Tax Receivable	165	64
Long-Term Receivable of VIE	601	580
Other Special Funds	230	212
Goodwill	16	16
Other Intangibles	122	84
Derivative Contracts	91	77
Restricted Cash of VIEs	—	24
Other	279	289
Total Noncurrent Assets	7,615	7,625
TOTAL ASSETS	$36,424	$35,333

See Notes to Condensed Consolidated Financial Statements.

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

	September 30, 2015	December 31, 2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$1,038	$624
Securitization Debt of VIEs Due Within One Year	68	259
Commercial Paper and Loans	20	—
Accounts Payable	1,046	1,178
Derivative Contracts	70	132
Accrued Interest	123	95
Accrued Taxes	204	21
Deferred Income Taxes	—	173
Clean Energy Program	185	142
Obligation to Return Cash Collateral	126	121
Regulatory Liabilities	208	186
Regulatory Liabilities of VIEs	3	—
Other	513	547
Total Current Liabilities	3,604	3,478
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,672	7,303
Regulatory Liabilities	181	258
Regulatory Liabilities of VIEs	—	39
Asset Retirement Obligations	776	743
Other Postretirement Benefit (OPEB) Costs	1,250	1,277
OPEB Costs of Servco	480	452
Accrued Pension Costs	373	440
Accrued Pension Costs of Servco	118	126
Environmental Costs	438	417
Derivative Contracts	23	33
Long-Term Accrued Taxes	287	208
Other	156	112
Total Noncurrent Liabilities	11,754	11,408
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Total Long-Term Debt	8,132	8,261
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2015 and 2014—533,556,660 shares	4,894	4,876
Treasury Stock, at cost, 2015— 28,238,912 shares; 2014— 27,720,068 shares	(667)	(635)
Retained Earnings	9,005	8,227
Accumulated Other Comprehensive Loss	(299)	(283)

Total Common Stockholders' Equity	12,933	12,185
Noncontrolling Interest	1	1
Total Stockholders' Equity	12,934	12,186
Total Capitalization	21,066	20,447
TOTAL LIABILITIES AND CAPITALIZATION	$36,424	$35,333

See Notes to Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$1,370	$1,042
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	960	919
Amortization of Nuclear Fuel	162	151
Provision for Deferred Income Taxes (Other than Leases) and ITC	230	103
Non-Cash Employee Benefit Plan Costs	121	36
Leveraged Lease (Income) Loss, Adjusted for Rents Received and Deferred Taxes	6	(30)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(87)	237
Change in Accrued Storm Costs	15	(3)
Net Change in Other Regulatory Assets and Liabilities	26	276
Cost of Removal	(82)	(68)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(2)	(99)
Net Change in Certain Current Assets and Liabilities:		
Tax Receivable	206	95
Accrued Taxes	127	127
Margin Deposit	142	(173)
Other Current Assets and Liabilities	15	(103)
Employee Benefit Plan Funding and Related Payments	(87)	(76)
Other	106	102
Net Cash Provided By (Used In) Operating Activities	3,228	2,536
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(2,782)	(1,922)
Proceeds from Sales of Capital Leases and Investments	12	11
Proceeds from Sales of Available-for-Sale Securities	1,120	1,224
Investments in Available-for-Sale Securities	(1,163)	(1,241)
Other	(28)	(60)
Net Cash Provided By (Used In) Investing Activities	(2,841)	(1,988)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	20	(60)
Issuance of Long-Term Debt	600	1,000
Redemption of Long-Term Debt	(300)	(500)
Redemption of Securitization Debt	(191)	(170)
Cash Dividends Paid on Common Stock	(592)	(561)
Other	(55)	(47)
Net Cash Provided By (Used In) Financing Activities	(518)	(338)
Net Increase (Decrease) in Cash and Cash Equivalents	(131)	210
Cash and Cash Equivalents at Beginning of Period	402	493

Cash and Cash Equivalents at End of Period	$271	$703
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$292	$284
Interest Paid, Net of Amounts Capitalized	$265	$269
Accrued Property, Plant and Equipment Expenditures	$321	$286

See Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$1,766	$1,655	$5,234	$5,235
OPERATING EXPENSES				
Energy Costs	740	668	2,176	2,278
Operation and Maintenance	391	366	1,171	1,190
Depreciation and Amortization	231	238	712	682
Total Operating Expenses	1,362	1,272	4,059	4,150
OPERATING INCOME	404	383	1,175	1,085
Other Income	22	16	59	44
Other Deductions	—	(2)	(2)	(3)
Interest Expense	(67)	(71)	(203)	(206)
INCOME BEFORE INCOME TAXES	359	326	1,029	920
Income Tax Expense	(137)	(126)	(398)	(355)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$222	$200	$631	$565

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
NET INCOME	$222	$200	$631	$565
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0 for the three and nine months ended 2015 and 2014, respectively	—	1	(1)	1
COMPREHENSIVE INCOME	$222	$201	$630	$566

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)

	September 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$14	$310
Accounts Receivable, net of allowances of $59 and $52 in 2015 and 2014, respectively	938	864
Accounts Receivable-Affiliated Companies	7	274
Unbilled Revenues	203	284
Materials and Supplies	146	133
Prepayments	109	42
Regulatory Assets	189	323
Regulatory Assets of VIEs	—	249
Derivative Contracts	4	18
Deferred Income Taxes	47	24
Restricted Cash of VIEs	26	—
Other	17	7
Total Current Assets	1,700	2,528
PROPERTY, PLANT AND EQUIPMENT	22,940	21,103
Less: Accumulated Depreciation and Amortization	(5,419)	(5,183)
Net Property, Plant and Equipment	17,521	15,920
NONCURRENT ASSETS		
Regulatory Assets	3,161	3,192
Long-Term Investments	335	348
Other Special Funds	52	53
Derivative Contracts	—	8
Restricted Cash of VIEs	—	24
Other	140	150
Total Noncurrent Assets	3,688	3,775
TOTAL ASSETS	$22,909	$22,223

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)

	September 30, 2015	December 31, 2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$171	$300
Securitization Debt of VIEs Due Within One Year	68	259
Commercial Paper and Loans	20	—
Accounts Payable	567	574
Accounts Payable—Affiliated Companies	208	379
Accrued Interest	80	68
Clean Energy Program	185	142
Deferred Income Taxes	—	165
Obligation to Return Cash Collateral	126	121
Regulatory Liabilities	208	186
Regulatory Liabilities of VIEs	3	—
Other	357	381
Total Current Liabilities	1,993	2,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,896	4,575
Other Postretirement Benefit (OPEB) Costs	929	967
Accrued Pension Costs	131	173
Regulatory Liabilities	181	258
Regulatory Liabilities of VIEs	—	39
Environmental Costs	387	364
Asset Retirement Obligations	304	290
Long-Term Accrued Taxes	165	116
Derivative Contracts	7	—
Other	58	67
Total Noncurrent Liabilities	7,058	6,849
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Total Long-Term Debt	6,441	6,012
STOCKHOLDER’S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2015 and 2014—132,450,344 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	4,843	4,212
Accumulated Other Comprehensive Income	1	2
Total Stockholder’s Equity	7,417	6,787
Total Capitalization	13,858	12,799

TOTAL LIABILITIES AND CAPITALIZATION	$22,909	$22,223

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)

	Nine Months Ended September 30,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$631	$565
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	712	682
Provision for Deferred Income Taxes and ITC	96	93
Non-Cash Employee Benefit Plan Costs	71	21
Cost of Removal	(82)	(68)
Change in Accrued Storm Costs	15	(3)
Net Change in Other Regulatory Assets and Liabilities	26	276
Net Change in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	30	71
Materials and Supplies	(13)	(15)
Prepayments	(67)	(92)
Accounts Payable	34	(3)
Accounts Receivable/Payable—Affiliated Companies, net	190	(113)
Other Current Assets and Liabilities	(18)	(6)
Employee Benefit Plan Funding and Related Payments	(72)	(67)
Other	(35)	2
Net Cash Provided By (Used In) Operating Activities	1,518	1,343
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,946)	(1,493)
Proceeds from Sales of Available-for-Sale Securities	16	98
Investments in Available-for-Sale Securities	(18)	(96)
Other	13	1
Net Cash Provided By (Used In) Investing Activities	(1,935)	(1,490)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Short-Term Debt	20	(60)
Issuance of Long-Term Debt	600	1,000
Redemption of Long-Term Debt	(300)	(500)
Redemption of Securitization Debt	(191)	(170)
Contributed Capital	—	175
Other	(8)	(11)
Net Cash Provided By (Used In) Financing Activities	121	434
Net Increase (Decrease) In Cash and Cash Equivalents	(296)	287
Cash and Cash Equivalents at Beginning of Period	310	18
Cash and Cash Equivalents at End of Period	$14	$305
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$(29)	$174

Interest Paid, Net of Amounts Capitalized	$186	$188
Accrued Property, Plant and Equipment Expenditures	$251	$238

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
OPERATING REVENUES	$1,096	$1,138	$3,846	$3,824
OPERATING EXPENSES				
Energy Costs	367	472	1,669	2,036
Operation and Maintenance	263	242	748	871
Depreciation and Amortization	75	71	226	215
Total Operating Expenses	705	785	2,643	3,122
OPERATING INCOME	391	353	1,203	702
Income from Equity Method Investments	3	4	11	11
Other Income	25	56	109	135
Other Deductions	(14)	(6)	(32)	(25)
Other-Than-Temporary Impairments	(30)	(10)	(45)	(14)
Interest Expense	(30)	(31)	(94)	(92)
INCOME BEFORE INCOME TAXES	345	366	1,152	717
Income Tax Expense	(139)	(144)	(445)	(277)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$206	$222	$707	$440

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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
NET INCOME	$206	$222	$707	$440
Other Comprehensive Income (Loss), net of tax				
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $32, $34, $33 and $23 for the three and nine months ended 2015 and 2014, respectively	(29)	(30)	(29)	(19)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $0, $6 and $(2) for the three and nine months ended 2015 and 2014, respectively	—	1	(9)	4
Pension/OPEB adjustment, net of tax (expense) benefit of $(5), $(1), $(15) and $(4) for the three and nine months ended 2015 and 2014, respectively	7	2	21	7
Other Comprehensive Income (Loss), net of tax	(22)	(27)	(17)	(8)
COMPREHENSIVE INCOME	$184	$195	$690	$432

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)

	September 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$15	$9
Accounts Receivable	218	334
Accounts Receivable—Affiliated Companies	158	313
Tax Receivable	3	3
Short-Term Loan to Affiliate	865	584
Fuel	451	538
Materials and Supplies, net	324	350
Derivative Contracts	147	207
Prepayments	36	17
Other	7	4
Total Current Assets	2,224	2,359
PROPERTY, PLANT AND EQUIPMENT	11,273	10,732
Less: Accumulated Depreciation and Amortization	(3,366)	(3,217)
Net Property, Plant and Equipment	7,907	7,515
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,715	1,780
Long-Term Investments	116	121
Goodwill	16	16
Other Intangibles	122	84
Other Special Funds	56	49
Derivative Contracts	91	62
Other	67	60
Total Noncurrent Assets	2,183	2,172
TOTAL ASSETS	$12,314	$12,046

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)

	September 30, 2015	December 31, 2014
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$853	$300
Accounts Payable	315	424
Accounts Payable-Affiliated Companies	117	118
Derivative Contracts	70	132
Deferred Income Taxes	44	43
Accrued Interest	43	27
Other	132	140
Total Current Liabilities	1,574	1,184
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	2,148	2,065
Asset Retirement Obligations	469	450
Other Postretirement Benefit (OPEB) Costs	258	248
Derivative Contracts	16	33
Accrued Pension Costs	134	153
Long-Term Accrued Taxes	54	41
Other	121	71
Total Noncurrent Liabilities	3,200	3,061
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	1,691	2,243
MEMBER'S EQUITY		
Contributed Capital	2,215	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,865	4,558
Accumulated Other Comprehensive Loss	(245)	(228)
Total Member's Equity	5,849	5,558
TOTAL LIABILITIES AND MEMBER'S EQUITY	$12,314	$12,046

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)

	Nine Months Ended September 30,	
	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$707	$440
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	226	215
Amortization of Nuclear Fuel	162	151
Provision for Deferred Income Taxes and ITC	109	5
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(87)	237
Non-Cash Employee Benefit Plan Costs	36	10
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(2)	(99)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	113	17
Margin Deposit	142	(173)
Accounts Receivable	54	49
Accounts Payable	(99)	(135)
Accounts Receivable/Payable—Affiliated Companies, net	115	299
Other Current Assets and Liabilities	(26)	28
Employee Benefit Plan Funding and Related Payments	(9)	(5)
Other	117	71
Net Cash Provided By (Used In) Operating Activities	1,558	1,110
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(797)	(414)
Proceeds from Sales of Available-for-Sale Securities	1,057	882
Investments in Available-for-Sale Securities	(1,083)	(898)
Short-Term Loan—Affiliated Company, net	(281)	167
Other	(46)	(63)
Net Cash Provided By (Used In) Investing Activities	(1,150)	(326)
CASH FLOWS FROM FINANCING ACTIVITIES		
Cash Dividend Paid	(400)	(775)
Other	(2)	(3)
Net Cash Provided By (Used In) Financing Activities	(402)	(778)
Net Increase (Decrease) in Cash and Cash Equivalents	6	6
Cash and Cash Equivalents at Beginning of Period	9	6
Cash and Cash Equivalents at End of Period	$15	$12
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$284	$87
Interest Paid, Net of Amounts Capitalized	$76	$78
Accrued Property, Plant and Equipment Expenditures	$70	$66

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

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), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power 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:

- 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 Federal Energy Regulatory Commission (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.
- 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 FERC, the Nuclear Regulatory Commission (NRC) and the states in which they operate.

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 operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an 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, 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 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, 2014.

Note 2. Recent Accounting Standards

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 was originally to be effective for annual and interim reporting periods beginning after December 15, 2016; however, the Financial Accounting Standards Board issued new guidance deferring the effective date by one year to periods beginning after December 31, 2017. Early application will be permitted as of the original effective date. We are currently analyzing the impact of this standard on our financial statements.

Amendments to the Consolidation Analysis

This standard was issued to respond to concerns regarding the current accounting for consolidation of certain legal entities. Under the new standard, all legal entities are subject to reevaluation under a revised consolidation model which will determine whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; eliminate the presumption that a general partner should consolidate a limited partnership; affect the consolidation analysis of reporting entities that are involved with VIEs and provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities who must comply with other requirements.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. We are currently analyzing the impact of this standard on our financial statements.

Simplifying the Presentation of Debt Issuance Costs

This standard was issued to simplify presentation of debt issuance costs. The standard will require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by this standard.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. We do not expect the impact of adoption of this standard to be material to our Condensed Consolidated Balance Sheets.

Note 3. Variable Interest Entities (VIEs)

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

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

The assets and liabilities of 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 September 30, 2015 and December 31, 2014. 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 nine months of 2015 or in 2014. PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II. In June 2015, Transition Funding II paid its final securitization bond payment and Transition Funding I is scheduled to make its final securitization bond payment in December 2015.

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 Operation and Maintenance (O&M) Expense, respectively. Servco recorded $96 million and $107 million for the three months and $262 million and $307 million for the nine months ended September 30, 2015 and 2014, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. 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 5. Regulatory Assets and Liabilities to the Consolidated Financial Statements in the Annual Report on Form 10-K for the year ended December 31, 2014.

In addition to items previously reported in the Annual Report on Form 10-K, significant 2015 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- Energy Strong Recovery Filing—In June 2015, PSE&G updated its Energy Strong electric and gas cost recovery petition filed in March 2015 seeking BPU approval to recover in base rates estimated annual increases in electric revenues of $6 million and gas revenues of $17 million. These increases represent a return on investment and recovery of Energy Strong capitalized investment costs placed in service from December 1, 2014 through May 31, 2015 for electric and from June 1, 2014 through May 31, 2015 for gas. In August 2015, the BPU provisionally approved PSE&G's request effective September 1, 2015.

In September 2015, PSE&G filed its Energy Strong electric cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs placed in service from June 1, 2015 through November 30, 2015. The annualized requested increase in electric revenue requirements is $14 million. The petition requests rates to be effective March 1, 2016, consistent with the BPU Order of approval of the Energy Strong Program. This matter is pending.

- Basic Gas Supply Service (BGSS)—In March 2015, PSE&G filed a letter with the BPU to extend the 28 cents per therm residential rate reduction via a bill credit for one additional month through April 30, 2015, which provided an additional approximate $31 million credit to customers.

In April 2015, the BPU issued an Order approving PSE&G's provisional BGSS rate of 45 cents per therm which had been implemented on October 1, 2014.

In June 2015, PSE&G made its Annual BGSS Filing with the BPU requesting a reduction of $70 million in annual BGSS revenues. In September 2015, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 45 cents to 40 cents per therm effective October 1, 2015.

- Weather Normalization Clause—On April 15, 2015, the BPU approved PSE&G's final filing with respect to excess revenues collected during the colder than normal 2013-2014 Winter Period (October 1, 2013 through May 31, 2014). Effective October 1, 2014, PSEG commenced returning $45 million in revenues to its customers during the 2014-2015 Winter Period (October 1, 2014 through May 31, 2015).

In September 2015, the BPU approved PSE&G's filing on a provisional basis with respect to excess revenues collected during the colder than normal 2014-2015 Winter Period. Effective October 1, 2015, PSE&G commenced returning $40 million in revenues to its customers during the 2015-2016 Winter Period (October 1, 2015 through May 31, 2016).

- Solar and Energy Efficiency - Green Program Recovery Charges (GPRC) and Solar Pilot Recovery Charge

(SPRC)—In April 2015, the BPU approved PSE&G's petition for an Energy Efficiency Economic Stimulus Extension II Program (EEE Ext II) to extend three EEE subprograms (multi-family, direct install and hospital efficiency). The Order allows PSE&G to extend the subprogram offerings under the same clause recovery process as its existing EEE Program and allows for $95 million of additional capital expenditures over the next three years and an allowance for

$12 million of additional administrative expenses over the next 15 years. The EEE Ext II program was added as a ninth component of the GPRC rate effective May 1, 2015.

In July of each year, PSE&G files for annual recovery for its Green Program investments which include a return on its investment and recovery of expenses. In May 2015, the BPU approved PSE&G's July 2014 filing requesting recovery of costs and investments in the first eight combined components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. In July 2015, PSE&G filed its annual GPRC and SPRC cost recovery petitions with the BPU, requesting recovery of costs and investments for the first eight combined components of the electric and gas GPRC, as well as the electric SPRC. The filings proposed rates for the period October 1, 2015 through September 30, 2016 designed to recover approximately $66 million and $10 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs. In September 2015, the BPU approved the July 2015 filings on a provisional basis, with new rates effective October 1, 2015.

- Transmission Formula Rate Filings—In June 2015, PSE&G filed its 2014 true-up adjustment pertaining to its formula rates in effect for 2014, which resulted in an adjustment of $19 million less than the 2014 filed revenues. The adjustment was primarily due to the impact of bonus depreciation and lower interest rates which PSE&G had recognized in its Consolidated Statement of Operations for the year ended December 31, 2014.

The 2016 Annual Formula Rate Update was filed with FERC in October 2015 and provides for approximately $146 million in increased annual transmission revenues effective January 1, 2016.

- Remediation Adjustment Charge (RAC)—In August 2015, the BPU approved PSE&G's filing with respect to its RAC 22 petition allowing recovery of $85 million effective September 1, 2015 related to net Manufactured Gas Plant expenditures from August 1, 2013 through July 31, 2014.
- Universal Service Fund (USF)/Lifeline—In September 2015, the BPU approved rates set to recover costs incurred under the USF/Lifeline energy assistance programs effective October 1, 2015. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.

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. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Condensed Consolidated Balance Sheets. 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 September 30, 2015	As of December 31, 2014
	Millions	
Commercial/Industrial	$180	$188
Residential	13	13
Total	$193	$201

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Energy Holdings

Energy Holdings, through several 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 September 30, 2015 and December 31, 2014, respectively.

	As of September 30, 2015	As of December 31, 2014
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$631	$691
Estimated Residual Value of Leased Assets	519	525
Unearned and Deferred Income	(368)	(380)
Gross Investment in Leases	782	836
Deferred Tax Liabilities	(706)	(738)
Net Investment in Leases	$76	$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.

	Lease Receivables, Net of Non-Recourse Debt
Counterparties' Credit Rating (Standard & Poor's (S&P)) As of September 30, 2015	As of September 30, 2015
	Millions
AA	$17
BBB+ — BBB-	316
BB-	134
B-	164
Total	$631

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 September 30, 2015, the gross investment in the leases of such assets, net of non-recourse debt, was $573 million ($(13) million, net of deferred taxes). A more detailed description of such assets under lease, as of September 30, 2015, is presented in the following table.

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Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counter-parties' S&P Credit Ratings As of September 30, 2015 (A)	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	$121	17	% 1,711	Coal	B-	NRG REMA, LLC
Conemaugh Station Units 1 and 2	PA	$121	17	% 1,711	Coal	B-	NRG REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$113	100	% 603	Coal	B-	NRG REMA, LLC

(A) On October 2, 2015, S&P lowered the B- rating for NRG REMA, LLC, an indirect subsidiary of NRG Energy, Inc., to CCC+. Potential adverse consequences relevant to the downgrade are discussed in the following paragraph.

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

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.

In early 2014, NRG REMA, LLC had disclosed its plan to place the Shawville generating facility in a "long-term protective layup" by April 2015 as it evaluated its alternatives under the lease. However, NRG has since notified PJM that it deactivated the coal-fired units at the Shawville generating facility in June 2015 and has disclosed that it expects to return the Shawville units to service in the summer of 2016 with the ability to use natural gas.

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 September 30, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$667	$176	$(18)	$825
Debt Securities				
Government Obligations	445	10	(1)	454
Other Debt Securities	402	6	(7)	401
Total Debt Securities	847	16	(8)	855
Other Securities	35	—	—	35
Total NDT Available-for-Sale Securities	$1,549	$192	$(26)	$1,715

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$685	$220	$(8)	$897
Debt Securities				
Government Obligations	430	9	(1)	438
Other Debt Securities	333	9	(3)	339
Total Debt Securities	763	18	(4)	777
Other Securities	106	—	—	106
Total NDT Available-for-Sale Securities	$1,554	$238	$(12)	$1,780

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 September 30, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$10	$10
Accounts Payable	$4	$2

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
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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 September 30, 2015				As of December 31, 2014			
	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)	$143	$(18)	$1	$—	$162	$(8)	$1	$—
Debt Securities								
Government Obligations (B)	90	(1)	15	—	95	—	28	(1)
Other Debt Securities (C)	164	(5)	29	(2)	99	(1)	30	(2)
Total Debt Securities	254	(6)	44	(2)	194	(1)	58	(3)
NDT Available-for-Sale Securities	$397	$(24)	$45	$(2)	$356	$(9)	$59	$(3)

(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 September 30, 2015.

(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 September 30, 2015.

(C) Debt Securities (Other)—Power's investments in corporate bonds, collateralized mortgage obligations, asset-backed securities and municipal government obligations 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 September 30, 2015.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	Millions			
Proceeds from NDT Fund Sales (A)	$215	$221	$1,037	$779
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	14	45	47	101
Gross Realized Losses	(11)	(3)	(24)	(12)
Net Realized Gains (Losses) on NDT Fund	$3	$42	$23	$89

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

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 $82 million (after-tax) were a component of Accumulated Other Comprehensive Loss on PSEG's and Power’s Condensed Consolidated Balance Sheets as of September 30, 2015.

The NDT available-for-sale debt securities held as of September 30, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$8
1 - 5 years	236
6 - 10 years	201
11 - 15 years	51
16 - 20 years	51
Over 20 years	308
Total NDT Available-for-Sale Debt Securities	$855

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 nine months ended September 30, 2015, other-than-temporary impairments of $45 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 September 30, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$11	$9	$—	$20
Debt Securities				
Government Obligations	106	1	(1)	106
Other Debt Securities	86	—	(2)	84
Total Debt Securities	192	1	(3)	190
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	$204	$10	$(3)	$211

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	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$12	$11	$—	$23
Debt Securities				
Government Obligations	89	2	—	91
Other Debt Securities	74	1	—	75
Total Debt Securities	163	3	—	166
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	$177	$14	$—	$191

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 September 30, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$1	$1
Accounts Payable	$1	$—

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

	As of September 30, 2015				As of December 31, 2014			
	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)	47	(2)	2	—	2	—	—	—
Other Debt Securities (C)	41	(1)	9	—	24	—	—	—
Total Debt Securities	88	(3)	11	—	26	—	—	—
Rabbi Trust Available-for-Sale Securities	$88	$(3)	$11	$—	$26	$—	$—	$—

(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 September 30, 2015.

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(C) Debt Securities (Other)—PSEG's investments in corporate bonds, collateralized mortgage obligations, asset-backed securities and municipal government obligations are limited to 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 September 30, 2015.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	Millions			
Proceeds from Rabbi Trust Sales (A)	$20	$419	$83	$445
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$—	$2	$2	$4
Gross Realized Losses	(1)	(2)	(1)	(3)
Net Realized Gains (Losses) on Rabbi Trust	$(1)	$—	$1	$1

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains disclosed in the preceding table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $4 million (after-tax) were a component of Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of September 30, 2015.

The Rabbi Trust available-for-sale debt securities held as of September 30, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$5
1 - 5 years	49
6 - 10 years	39
11 - 15 years	8
16 - 20 years	9
Over 20 years	80
Total Rabbi Trust Available-for-Sale Debt Securities	$190

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, PSE&G and Power are detailed as follows:

	As of September 30, 2015	As of December 31, 2014
	Millions	
PSE&G	$42	$41
Power	52	45
Other	117	105
Total Rabbi Trust Available-for-Sale Securities	$211	$191

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 Three Months Ended September 30,		OPEB Three Months Ended September 30,		Pension Benefits Nine Months Ended September 30,		OPEB Nine Months Ended September 30,	
	2015	2014	2015	2014	2015	2014	2015	2014
	Millions							
Components of Net Periodic Benefit Costs (Credit)								
Service Cost	$30	$26	$5	$5	$92	$78	$16	$14
Interest Cost	59	58	16	18	176	176	50	52
Expected Return on Plan Assets	(103)	(99)	(7)	(7)	(310)	(299)	(22)	(20)
Amortization of Net Prior Service Cost (Credit)	(5)	(5)	(4)	(4)	(14)	(14)	(11)	(11)
Actuarial Loss	38	14	11	6	112	42	32	18
Total Benefit Costs (Credit)	$19	$(6)	$21	$18	$56	$(17)	$65	$53

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

	Pension Benefits Three Months Ended September 30,		OPEB Three Months Ended September 30,		Pension Benefits Nine Months Ended September 30,		OPEB Nine Months Ended September 30,	
	2015	2014	2015	2014	2015	2014	2015	2014
	Millions							
PSE&G	$10	$(4)	$13	$12	$30	$(14)	$41	$35
Power	5	(2)	7	5	16	(5)	20	15
Other	4	—	1	1	10	2	4	3

Total Benefit Costs (Credit)	$19	$(6)	$21	$18	$56	$(17)	$65	$53

During the three months ended March 31, 2015, PSEG contributed its entire planned contributions for the year 2015 of $15 million into its pension plans and $14 million into its OPEB plan for 2015.

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. 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. Servco's pension-related revenues and costs were $17 million and $30 million for the three months and nine months ended September 30, 2015, respectively, completing its entire planned contribution for the year 2015. Servco's pension-related revenues and costs were $21 million and $67 million for the three months and nine months ended September 30, 2014, respectively. The OPEB-related revenues earned and costs incurred for each of the three months and nine months ended September 30, 2015 and 2014 were immaterial.

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
- all of the related contracts would have to be “out-of-the-money” (if the contracts are terminated, Power would owe money to the counterparties).

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

Power is subject to

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

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

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The face value of Power's outstanding guarantees, current exposure and margin positions as of September 30, 2015 and December 31, 2014 are shown as follows:

	As of September 30, 2015	As of December 31, 2014
	Millions	
Face Value of Outstanding Guarantees	$1,733	$1,814
Exposure under Current Guarantees	$184	$273
Letters of Credit Margin Posted	$178	$159
Letters of Credit Margin Received	$80	$40
Cash Deposited and Received:		
Counterparty Cash Margin Deposited	$—	$—
Counterparty Cash Margin Received	$(44)	$(13)
Net Broker Balance Deposited (Received)	$4	$115
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$796	$945
Liquidity Available under PSEG’s and Power’s Credit Facilities to Post Collateral	$3,375	$3,495
Additional Amounts Posted:		
Other Letters of Credit	$47	$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 and Moody’s ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

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. PSEG had also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

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.

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

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a “Superfund” 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 further determined that there was a 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.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G’s former MGP sites and approximately one percent is attributable to Power’s generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus’ predecessor company’s (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G. This agreement and the work undertaken pursuant to the action agreement will not affect the ultimate remedy that the EPA will select for the remediation of the 17-mile stretch of the lower Passaic River.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA’s portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, 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. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft “Focused Feasibility Study” (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River. The EPA’s estimated costs to remediate the lower eight miles of the Passaic River range from $365 million for a targeted remedy to $3.3 billion for a deep dredge of this portion of the Passaic River. The EPA also identified in the revised draft FFS its preferred alternative, which would involve dredging the lower eight miles of the river bank-to-bank and installing an engineered cap. The estimated cost in the revised draft FFS for the EPA's preferred alternative is $1.7 billion. No provisional cost allocation has been made by the CPG for the work contemplated by the revised draft FFS, and the work contemplated by the revised draft FFS is not subject to the CPG’s cost sharing allocation agreed to in connection with the removal work for River Mile 10.9 or in connection with the conduct of the RI/FS.

The revised draft FFS was subject to a public comment period, and remains subject to the EPA’s response to comments submitted, a design phase and at least an estimated five years for completion of the work. The public comment period for the revised draft FFS closed on August 21, 2014. Over 300 comments were submitted by a variety of entities

potentially impacted by the revised draft FFS, including the CPG, individual companies, municipalities, public officials, citizens groups, Amtrak, NJ Transit and others.

The CPG, which consisted of 60 members as of September 30, 2015, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $151 million, which the CPG continues to incur. Of the estimated $151 million, as of August 31, 2015, the CPG had spent approximately $141 million, of which PSEG's total share was approximately $9 million.

The draft FS sets forth various alternatives for remediating the lower Passaic River. The draft FS sets forth the CPG’s estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranges from approximately $518 million to $772 million. No provisional cost allocation has been made

by the CPG for the work contemplated by the draft FS. However, based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimates of their share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

The EPA will consider the comments received on its revised draft FFS and is expected to consider the CPG's RI/FS prior to issuing a Record of Decision (ROD) of a selected remedy for the lower Passaic River. The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS is finalized, (ii) a final remedy is determined by the EPA or through litigation, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on our financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (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 New Jersey Spill Compensation and Control 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 and Power are unable to estimate their respective portions 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. PSE&G and Power are unable to estimate their respective portions 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 $450 million and $518 million through 2021, including its $10 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $450 million as of September 30, 2015. Of this amount, $73 million was recorded in Other Current Liabilities and $377 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $450 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.

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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.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System 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 (NJDEP) manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

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 June 30, 2015, the NJDEP issued a draft Salem permit. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period. The NJDEP may make revisions before issuing the final permit expected during the first half of 2016. Power participated in the NJDEP's August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015.

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. On August 15, 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. On September 5, 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the endangered species act provisions of the 316 (b) rule. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

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 $1.0 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.

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance

In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the Connecticut Department of Energy and Environmental Protection of the

issues and has taken actions to investigate and resolve the potential non-compliance. At this early stage Power cannot predict the impact of this matter.

Steam Electric Effluent Guidelines

On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Mercer and Bridgeport Harbor stations have bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if these new standards will have a material impact on Power's future capital requirements, financial condition or results of operations.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power’s results of operations, financial condition or cash flows.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, are residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category are larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Pricing (CIEP)). 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 winning BGS suppliers, including Power, 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.

The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2015 is $272.78 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2015 of $282.04 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.

PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2012	2013	2014	2015	
36-Month Terms Ending	May 2015	May 2016	May 2017	May 2018	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per MWh	$83.88	$92.18	$97.39	$99.54	

(A)

Prices set for the 2015 BGS auction year became effective on June 1, 2015 when the 2012 BGS auction agreements expired.

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 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'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 2020 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

Power also has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available, Power can use the gas to supply its fossil generating stations.

As of September 30, 2015, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2019 Millions
Nuclear Fuel	
Uranium	$440
Enrichment	$345
Fabrication	$179
Natural Gas	$1,001
Coal	$331

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. 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. 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 FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors and modified the bid quantities for its peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future. On September 2, 2014, FERC Staff initiated a preliminary, non-public staff investigation into the matter. This investigation, which is ongoing, could result in FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies.

During the three months ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. It is not possible at this time to reasonably estimate the potential range of loss or full impact or predict any resulting penalties or other costs associated with this matter, or the applicability of mitigating factors. As new information becomes available or future developments occur

in this investigation, it is possible that Power will record additional estimated losses and such additional losses may be material.

New Jersey Clean Energy Program

In June 2015, the BPU established the funding level for fiscal year 2016 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2016 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 $185 million as of September 30, 2015 for its outstanding share of the fiscal

year 2016 and remaining fiscal year 2015 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.

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. In June 2013, PSEG, PSE&G and Power filed suit in New Jersey state court (NJ 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.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in O&M Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. Of the $295 million, $36 million related to insured property. In 2012, PSE&G recognized $6 million of insurance recoveries, which were deferred. There were no significant additional costs incurred since 2012.

PSE&G made a filing with the BPU to review the prudency of unreimbursed incremental storm restoration costs, including O&M and capital expenditures associated with Superstorm Sandy and certain other extreme weather events, for recovery in its next base rate case or sooner through a BPU-approved cost recovery mechanism. In September 2014, the BPU approved its filing.

Power had incurred a total of $193 million of storm-related costs from 2012 through 2014, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized primarily in O&M Expense, offset by $44 million of insurance recoveries in 2013 and 2012. Power incurred an additional $2 million of storm-related costs in 2015 which were recognized primarily in O&M Expense.

In the first half of 2015, PSEG reached settlements with its insurers with respect to claims for coverage of its Superstorm Sandy-related losses. PSEG received an additional $214 million under these settlements (consisting of $159 million and $55 million recognized in the three months ended March 31, 2015 and June 30, 2015, respectively), bringing cumulative insurance proceeds to $264 million. Of the $214 million recognized in 2015, PSE&G and Power recorded $35 million and $179 million, respectively. In addition to the $35 million recognized in 2015, PSE&G recognized the aforementioned $6 million of previously deferred insurance recoveries, resulting in reductions in Regulatory Assets of $20 million, O&M Expense of $10 million and Property, Plant and Equipment of $11 million. Power recorded reductions in both O&M Expense of $145 million and Property, Plant and Equipment of $6 million and an increase in Other Income of $28 million.

The claim filed by PSEG, PSE&G and Power related to Superstorm Sandy insurance coverage is now fully resolved.

Note 9. Changes in Capitalization

The following capital transactions occurred in the nine months ended September 30, 2015:

PSE&G

- issued $350 million of 3.00% Secured Medium-Term Notes, Series K due May 2025,
- issued $250 million of 4.05% Secured Medium-Term Notes, Series K due May 2045,
- paid $300 million of 2.70% Secured Medium-Term Notes at maturity,
- paid $183 million of Transition Funding's securitization debt, and
- paid the final $8 million of Transition Funding II's securitization debt.

Power

- paid cash dividends of $400 million to PSEG.

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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.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but do not qualify for or are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and changes in the fair value of these contracts are recorded in earnings each period.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. 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

PSEG and Power use forward sale contracts, swaps and futures contracts to hedge certain forecasted natural gas sales made to support the BGSS contract with PSE&G. These derivative transactions qualify and are designated as cash flow hedges.

As of September 30, 2015 and December 31, 2014, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity were as follows:

	As of September 30, 2015	As of December 31, 2014
	Millions	
Fair Value of Cash Flow Hedges	$2	$18
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$1	$10

The expiration date of the longest-dated cash flow hedge at Power is in December 2015. Power's remaining $1 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 September 30, 2015.

Economic Hedges

Power enters into derivative contracts that do not qualify or are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to certain long-term natural gas sales derivative contracts to optimize its pipeline capacity utilization. Changes in the fair market value of these contracts are recorded in Regulatory Assets and Regulatory 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 and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of September 30, 2015, PSEG had 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 September 30, 2015 and December 31, 2014, the fair value of all the underlying hedges was $11 million and $22 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 immaterial as of September 30, 2015 and December 31, 2014, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. 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 on the Condensed Consolidated Balance Sheets of Power, PSE&G and PSEG.

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The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of September 30, 2015						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts	Not Designated Energy-Related Contracts	Netting (B)	Total Power	Not Designated Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$2	$413	$(268)	$147	$4	$11	$162
Noncurrent Assets	—	284	(193)	91	—	—	91
Total Mark-to-Market Derivative Assets	$2	$697	$(461)	$238	$4	$11	$253
Derivative Contracts							
Current Liabilities	$—	$(311)	$241	$(70)	$—	$—	$(70)
Noncurrent Liabilities	—	(178)	162	(16)	(7)	—	(23)
Total Mark-to-Market Derivative (Liabilities)	$—	$(489)	$403	$(86)	$(7)	$—	$(93)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$2	$208	$(58)	$152	$(3)	$11	$160

	As of December 31, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts	Not Designated Energy-Related Contracts	Netting (B)	Total Power	Not Designated Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$18	$597	$(408)	$207	$18	$15	$240
Noncurrent Assets	—	171	(109)	62	8	7	77
Total Mark-to-Market Derivative Assets	$18	$768	$(517)	$269	$26	$22	$317
Derivative Contracts							
Current Liabilities	$—	$(568)	$436	$(132)	$—	$—	$(132)
Noncurrent Liabilities	—	(138)	105	(33)	—	—	(33)
Total Mark-to-Market Derivative (Liabilities)	$—	$(706)	$541	$(165)	$—	$—	$(165)
Total Net Mark-to-Market Derivative Assets	$18	$62	$24	$104	$26	$22	$152

(Liabilities)

(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 September 30, 2015 and December 31, 2014. 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 on the Condensed Consolidated Balance Sheets. As of September 30, 2015 and

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December 31, 2014, net cash collateral (received) paid of $(58) million and $24 million, respectively, were netted against the corresponding net derivative contract positions. Of the $(58) million as of September 30, 2015, $(32) million and $(38) million of cash collateral were netted against current assets and noncurrent assets, respectively, and $5 million and $7 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $24 million as of December 31, 2014, $(4) million and $(8) million were netted against current assets and noncurrent assets, respectively, and $32 million and $4 million were netted against current liabilities and noncurrent 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 to a below investment grade 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 the NYMEX and ICE that are fully collateralized) was $78 million and $127 million as of September 30, 2015 and December 31, 2014, respectively. As of September 30, 2015 and December 31, 2014, Power had the contractual right of offset of $12 million and $18 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 to a below investment grade rating, it would have had additional collateral obligations of $66 million and $109 million as of September 30, 2015 and December 31, 2014, 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 $796 million and $945 million as of September 30, 2015 and December 31, 2014, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

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 September 30, 2015 and 2014.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended September 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 September 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 September 30,	
	2015	2014		2015	2014		2015	2014
	Millions							
PSEG	$1	$3	Operating Revenues	$—	$1	Operating Revenues	$—	$—

Energy-Related Contracts								
Total PSEG	$1	$3		$—	$1		$—	$—
Power								
Energy-Related Contracts	$1	$3	Operating Revenues	$—	$1	Operating Revenues	$—	$—
Total Power	$1	$3		$—	$1		$—	$—

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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 nine months ended September 30, 2015 and 2014.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Nine Months Ended September 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) Nine Months Ended September 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) Nine Months Ended September 30,	
	2015	2014		2015	2014		2015	2014
	Millions							
PSEG								
Energy-Related Contracts	$2	$(4)	Operating Revenues	$17	$(11)	Operating Revenues	$—	$—
Total PSEG	$2	$(4)		$17	$(11)		$—	$—
Power								
Energy-Related Contracts	$2	$(4)	Operating Revenues	$17	$(11)	Operating Revenues	$—	$—
Total Power	$2	$(4)		$17	$(11)		$—	$—

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, 2014	$17	$10
Gain Recognized in AOCI	1	1
Less: Gain Reclassified into Income	(17)	(10)
Balance as of June 30, 2015	$1	$1
Gain Recognized in AOCI	1	—
Less: Gain Reclassified into Income	—	—
Balance as of September 30, 2015	$2	$1

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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 nine months ended September 30, 2015 and 2014.

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 September 30,		Nine Months Ended September 30,	
		2015	2014	2015	2014
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$154	$93	$202	$(759)
Energy-Related Contracts	Energy Costs	(4)	(12)	(4)	65
Total PSEG and Power		$150	$81	$198	$(694)

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 NPNS 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 $15 million for each of the nine months ended September 30, 2015 and 2014, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of September 30, 2015 and December 31, 2014.

Type	Notional	Total	PSEG	Power	PSE&G
		Millions			
As of September 30, 2015					
Natural Gas	Dth	193	—	154	39
Electricity	MWh	291	—	291	—
Financial Transmission Rights (FTRs)	MWh	21	—	21	—
Interest Rate Swaps	U.S. Dollars	850	850	—	—
As of December 31, 2014					
Natural Gas	Dth	274	—	216	58
Electricity	MWh	310	—	310	—
FTRs	MWh	15	—	15	—
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 September 30, 2015, 98% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

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The following table provides information on Power's credit risk from others, net of cash collateral, as of September 30, 2015. 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	$348	$118	$230	2	$127	(A)
Non-Investment Grade—External Rating	1	—	1	—	—	
Investment Grade—No External Rating	11	—	11	—	—	
Non-Investment Grade—No External Rating	4	—	4	—	—	
Total	$364	$118	$246	2	$127	

(A) Represents net exposure of $87 million with PSE&G. The remaining net exposure of $40 million is with a non-affiliated power purchaser which is an investment grade counterparty.

As of September 30, 2015, collateral held from counterparties where Power had credit exposure included $43 million in cash collateral and $75 million in letters of credit.

As of September 30, 2015, Power had 133 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of September 30, 2015, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of September 30, 2015, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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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, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds.

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 September 30, 2015, these consisted primarily of long-term gas supply contracts and certain electric load contracts.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of September 30, 2015 and December 31, 2014, 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 PSE&G and Power.

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	Recurring Fair Value Measurements as of September 30, 2015				
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)	$226	$—	$226	$—	$—
Derivative Contracts:					
Energy-Related Contracts (B)	$242	$(461)	$—	$694	$9
Interest Rate Swaps (C)	$11	$—	$—	$11	$—
NDT Fund (D)					
Equity Securities	$825	$—	$824	$1	$—
Debt Securities—Govt Obligations	$454	$—	$—	$454	$—
Debt Securities—Other	$401	$—	$—	$401	$—
Other Securities	$35	$—	$35	$—	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$20	$—	$20	$—	$—
Debt Securities—Govt Obligations	$106	$—	$—	$106	$—
Debt Securities—Other	$84	$—	$—	$84	$—
Other Securities	$1	$—	$1	$—	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(93)	$403	$—	$(489)	$(7)
PSE&G					
Assets:					
Cash Equivalents (A)	$—	$—	$—	$—	$—
Derivative Contracts:					
Energy-Related Contracts (B)	$4	$—	$—	$—	$4
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$4	$—	$4	$—	$—
Debt Securities—Govt Obligations	$21	$—	$—	$21	$—
Debt Securities—Other	$17	$—	$—	$17	$—
Other Securities	$—	$—	$—	$—	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(7)	$—	$—	$—	$(7)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$238	$(461)	$—	$694	$5
NDT Fund (D)					
Equity Securities	$825	$—	$824	$1	$—
Debt Securities—Govt Obligations	$454	$—	$—	$454	$—
Debt Securities—Other	$401	$—	$—	$401	$—

Other Securities	$35	$—	$35	$—	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—
Debt Securities—Govt Obligations	$26	$—	$—	$26	$—
Debt Securities—Other	$21	$—	$—	$21	$—
Other Securities	$—	$—	$—	$—	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(86)	$403	$—	$(489)	$—

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	Recurring Fair Value Measurements as of December 31, 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)	$365	$—	$365	$—	$—
Derivative Contracts:					
Energy-Related Contracts (B)	$295	$(517)	$—	$774	$38
Interest Rate Swaps (C)	$22	$—	$—	$22	$—
NDT Fund (D)					
Equity Securities	$897	$—	$896	$1	$—
Debt Securities—Govt Obligations	$438	$—	$—	$438	$—
Debt Securities—Other	$339	$—	$—	$339	$—
Other Securities	$106	$—	$106	$—	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$23	$—	$23	$—	$—
Debt Securities—Govt Obligations	$91	$—	$—	$91	$—
Debt Securities—Other	$75	$—	$—	$75	$—
Other Securities	$2	$—	$—	$2	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(165)	$541	$—	$(705)	$(1)
PSE&G					
Assets:					
Cash Equivalents (A)	$294	$—	$294	$—	$—
Derivative Contracts:					
Energy Related Contracts (B)	$26	$—	$—	$—	$26
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—
Debt Securities—Govt Obligations	$20	$—	$—	$20	$—
Debt Securities—Other	$16	$—	$—	$16	$—
Other Securities	$—	$—	$—	$—	$—
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$269	$(517)	$—	$774	$12
NDT Fund (D)					
Equity Securities	$897	$—	$896	$1	$—
Debt Securities—Govt Obligations	$438	$—	$—	$438	$—
Debt Securities—Other	$339	$—	$—	$339	$—
Other Securities	$106	$—	$106	$—	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—

Debt Securities—Govt Obligations	$21	$—	$—	$21	$—
Debt Securities—Other	$18	$—	$—	$18	$—
Other Securities	$1	$—	$—	$1	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(165)	$541	$—	$(705)	$(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 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, collateralized mortgage obligations, asset backed securities and government 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 Sheets. As of September 30, 2015, net cash collateral (received) paid of $(58) million, was netted against the corresponding net derivative contract positions. Of the $(58) million as of September 30, 2015, $(70) million of cash collateral was netted against assets, and $12 million was netted against liabilities. As of December 31, 2014, net cash collateral (received) paid of $24 million, was netted against the corresponding net derivative contract positions. Of the $24 million as of December 31, 2014, $(12) million of cash collateral was netted against assets, and $36 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 nonperformance risk were not material to the financial statements.

For PSE&G and Power, 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 fair value 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. The following tables provide details surrounding significant Level 3 valuations as of September 30, 2015 and December 31, 2014.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of September 30, 2015 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$4	$(7)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.90/dekatherm
Total PSE&G		$4	$(7)			
Power						
Electricity	Electric Load Contracts	$4	$—	Discounted Cash flow	Historic Load Variability	0% to +10%
Other	Various (A)	1	—			
Total Power		$5	$—			
Total PSEG		$9	$(7)			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2014 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contracts	$26	$—	Discounted Cash Flow	Transportation Costs	$0.70 to $1/dekatherm
Total PSE&G		$26	$—			
Power						
Electricity	Electric Load Contracts	$12	$(1)	Discounted Cash Flow	Historic Load Variability	0% to +10%
Other	Various (B)	—	—			
Total Power		$12	$(1)			
Total PSEG		$38	$(1)			

(A) Includes long-term electric positions which were immaterial as of September 30, 2015.

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

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 gas supply contracts where PSE&G is a seller, an increase in gas transportation cost would increase the fair value. 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.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and nine months ended September 30, 2015 and September 30, 2014, respectively, follows:
Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Three Months and Nine Months Ended September 30, 2015

	Three Months Ended September 30, 2015						
Description	Balance as of July 1, 2015	Total Gains or (Losses) Realized/Unrealized Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of September 30, 2015
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$8	$4	$ (8)	$—	$(2)	$—	$2
PSE&G							
Net Derivative Assets (Liabilities)	$5	$—	$ (8)	$—	$—	$—	$(3)
Power							
Net Derivative Assets (Liabilities)	$3	$4	$ —	$—	$(2)	$—	$5

	Nine Months Ended September 30, 2015						
Description	Balance as of January 1, 2015	Total Gains or (Losses) Realized/Unrealized Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of September 30, 2015
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$37	$12	$ (29)	$—	$(18)	$—	$2
PSE&G							
Net Derivative Assets (Liabilities)	$26	$—	$ (29)	$—	$—	$—	$(3)
Power							
Net Derivative Assets (Liabilities)	$11	$12	$ —	$—	$(18)	$—	$5

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

	Three Months Ended September 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of July 1, 2014	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2014
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$13	$(8)	$ (9)	$—	$(4)	$—	$(8)
PSE&G							
Net Derivative Assets (Liabilities)	$22	$—	$ (9)	$—	$—	$—	$13
Power							
Net Derivative Assets (Liabilities)	$(9)	$(8)	$ —	$—	$(4)	$—	$(21)

	Nine Months Ended September 30, 2014						
		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2014	Included in Income (E)	Included in Regulatory Assets/ Liabilities (B)	Purchases (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of September 30, 2014
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$88	$(66)	$ (81)	$—	$54	$(3)	$(8)
PSE&G							
Net Derivative Assets (Liabilities)	$94	$—	$ (81)	$—	$—	$—	$13
Power							
Net Derivative Assets (Liabilities)	$(6)	$(66)	$ —	$—	$54	$(3)	$(21)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities includes $4 million and $12 million in Operating Income for the three months and nine months ended September 30, 2015, respectively. Of the $4 million in Operating Income, $3 million is unrealized. Of the $12 million in Operating Income, $(6) 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 $(2) million and $(18) million in settlements for the three months and nine months ended September 30, 2015. Includes $(4) million and $54 million in settlements for the three months and nine months ended September 30, 2014.

(D) There were no transfers among levels during the three months ended September 30, 2015 and 2014 and the nine months ended September 30, 2015. During the nine months ended September 30, 2014, $(3) million of net derivative 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.

(E) PSEG’s and Power’s gains and losses attributable to changes in net derivative assets and liabilities include $(8) million and $(66) million in Operating Income for the three months and nine months ended September 30, 2014, respectively. Of the $(8) million in Operating Income, $(12) million is unrealized. Of the $(66) million in Operating Income, $(11) million is unrealized.

As of September 30, 2015, PSEG carried $2.3 billion of net assets that are measured at fair value on a recurring basis, of which $2 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of September 30, 2014, PSEG carried $2.5 billion of net assets that are measured at fair value on a recurring basis, of which $8 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 September 30, 2015 and December 31, 2014.

	As of September 30, 2015		As of December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$7	$11	$14	$22
PSE&G (B)	6,612	7,102	6,312	6,912
Transition Funding (PSE&G) (B)	68	69	251	261
Transition Funding II (PSE&G) (B)	—	—	8	8
Power - Recourse Debt (B)	2,544	2,856	2,543	2,930
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	7	7	16	16
Total Long-Term Debt	$9,238	$10,045	$9,144	$10,149

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

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

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

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Note 12. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated
	Millions			
Three Months Ended September 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$—	$24	$—	$24
Allowance for Funds Used During Construction	14	—	—	14
Solar Loan Interest	6	—	—	6
Other	2	1	—	3
Total Other Income	$22	$25	$—	$47
Nine Months Ended September 30, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$—	$78	$—	$78
Allowance for Funds Used During Construction	36	—	—	36
Solar Loan Interest	18	—	—	18
Gain on Insurance Recovery	—	28	—	28
Other	5	3	3	11
Total Other Income	$59	$109	$3	$171
Three Months Ended September 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$—	$55	$—	$55
Allowance for Funds Used During Construction	8	—	—	8
Solar Loan Interest	6	—	—	6
Other	2	1	3	6
Total Other Income	$16	$56	$3	$75
Nine Months Ended September 30, 2014				
NDT Fund Gains, Interest, Dividend and Other Income	$—	$133	$—	$133
Allowance for Funds Used During Construction	21	—	—	21
Solar Loan Interest	18	—	—	18
Other	5	2	6	13
Total Other Income	$44	$135	$6	$185

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Other Deductions	PSE&G	Power	Other (A)	Consolidated
	Millions			
Three Months Ended September 30, 2015				
NDT Fund Realized Losses and Expenses	$—	$13	$—	$13
Other	—	1	—	1
Total Other Deductions	$—	$14	$—	$14
Nine Months Ended September 30, 2015				
NDT Fund Realized Losses and Expenses	$—	$30	$—	$30
Other	2	2	2	6
Total Other Deductions	$2	$32	$2	$36
Three Months Ended September 30, 2014				
NDT Fund Realized Losses and Expenses	$—	$4	$—	$4
Other	2	2	1	5
Total Other Deductions	$2	$6	$1	$9
Nine Months Ended September 30, 2014				
NDT Fund Realized Losses and Expenses	$—	$18	$—	$18
Other	3	7	3	13
Total Other Deductions	$3	$25	$3	$31

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

Note 13. Income Taxes

PSEG’s, PSE&G’s and Power's effective tax rates for the three months and nine months ended September 30, 2015 and 2014 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
PSEG	39.4%	37.0%	38.8%	37.8%
PSE&G	38.2%	38.5%	38.7%	38.6%
Power	40.3%	39.4%	38.6%	38.6%

For the three months ended September 30, 2015, PSE&G's effective tax rate was lower than the statutory tax rate of 40.85% due primarily to the beneficial impact of plant related flow-through items.

For the nine months ended September 30, 2015, PSEG's and Power’s effective tax rates were lower than the statutory tax rate of 40.85% primarily due to a manufacturing deduction under Section 199 of the Internal Revenue Code (IRC) and the tax benefit associated with the income tax rate differential of carrying back federal net operating tax losses under section 172(f) of the IRC. PSE&G's effective tax rate was lower than the statutory tax rate due primarily to the beneficial impact of plant related flow-through items.

For the three months and nine months ended September 30, 2015, as compared to the same periods in the prior year, PSEG's increase was due primarily to the absence of the 2014 audit settlement.

In August 2014, PSEG received notice from the Internal Revenue Service (IRS) that the audit settlement covering tax years 2007 through 2010 had been approved by the Joint Committee on Taxation. This effectively settled all issues with the IRS through 2010. In September 2014, PSEG received refunds from the IRS totaling $121 million, representing the net settlement of all disputed amounts, including interest, through the tax year 2010. As a result of the

settlement of this audit, PSEG recorded a $12 million reduction of tax expense in the quarter ended September 30, 2014.

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

PSEG	Other Comprehensive Income (Loss) Three Months Ended September 30, 2015			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2015	$1	$(395)	$ 117	$(277)
Other Comprehensive Income before Reclassifications	—	—	(46)	(46)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	9	15	24
Net Current Period Other Comprehensive Income (Loss)	—	9	(31)	(22)
Balance as of September 30, 2015	$1	$(386)	$ 86	$(299)

	Other Comprehensive Income (Loss) Three Months Ended September 30, 2014			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2014	$1	$(232)	$ 158	$(73)
Other Comprehensive Income before Reclassifications	2	—	(15)	(13)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	3	(15)	(13)
Net Current Period Other Comprehensive Income (Loss)	1	3	(30)	(26)
Balance as of September 30, 2014	$2	$(229)	$ 128	$(99)

	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2015			
Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2014	$10	$(411)	$ 118	$(283)
Other Comprehensive Income before Reclassifications	1	—	(44)	(43)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	25	12	27
Net Current Period Other Comprehensive Income (Loss)	(9)	25	(32)	(16)
Balance as of September 30, 2015	$1	$(386)	$ 86	$(299)

	Other Comprehensive Income (Loss) Nine Months Ended September 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	(2)	—	19	17
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	6	9	(36)	(21)
Net Current Period Other Comprehensive Income (Loss)	4	9	(17)	(4)
Balance as of September 30, 2014	$2	$(229)	$ 128	$(99)

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Power

Other Comprehensive Income (Loss)
Three Months Ended September 30, 2015

Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2015	$2	$(337)	$ 112	$(223)
Other Comprehensive Income before Reclassifications	—	—	(43)	(43)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	—	7	14	21
Net Current Period Other Comprehensive Income (Loss)	—	7	(29)	(22)
Balance as of September 30, 2015	$2	$(330)	$ 83	$(245)

Other Comprehensive Income (Loss)
Three Months Ended September 30, 2014

Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of June 30, 2014	$2	$(199)	$ 153	$(44)
Other Comprehensive Income before Reclassifications	2	—	(14)	(12)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(1)	2	(16)	(15)
Net Current Period Other Comprehensive Income (Loss)	1	2	(30)	(27)
Balance as of September 30, 2014	$3	$(197)	$ 123	$(71)

Other Comprehensive Income (Loss)
Nine Months Ended September 30, 2015

Accumulated Other Comprehensive Income (Loss)	Cash Flow Hedges	Pension and OPEB Plans	Available-for-Sale Securities	Total
	Millions			
Balance as of December 31, 2014	$11	$(351)	$ 112	$(228)
Other Comprehensive Income before Reclassifications	1	—	(41)	(40)
Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	(10)	21	12	23
Net Current Period Other Comprehensive Income (Loss)	(9)	21	(29)	(17)
Balance as of September 30, 2015	$2	$(330)	$ 83	$(245)

Other Comprehensive Income (Loss)
Nine Months Ended September 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	$(1)	$(204)	$ 142	$(63)
Other Comprehensive Income before Reclassifications	(2)	—	17	15

Amounts Reclassified from Accumulated Other Comprehensive Income (Loss)	6	7	(36)	(23)
Net Current Period Other Comprehensive Income (Loss)	4	7	(19)	(8)
Balance as of September 30, 2014	$3	$(197)	$ 123	$(71)

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PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2015			Nine Months Ended September 30, 2015		
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	$—	$—	$—	$17	$(7)	$10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	9	(3)	6
Amortization of Actuarial Loss	O&M Expense	(17)	6	(11)	(51)	20	(31)
Total Pension and OPEB Plans		(14)	5	(9)	(42)	17	(25)
Available-for-Sale Securities							
Realized Gains	Other Income	14	(7)	7	49	(25)	24
Realized Losses	Other Deductions	(12)	5	(7)	(25)	12	(13)
Other-Than-Temporary Impairments (OTTI)	OTTI	(30)	15	(15)	(45)	22	(23)
Total Available-for-Sale Securities		(28)	13	(15)	(21)	9	(12)
Total		$(42)	$18	$(24)	$(46)	$19	$(27)

PSEG		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2014			Nine Months Ended September 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	$1	$—	$1	$(11)	$5	$(6)
Total Cash Flow Hedges		1	—	1	(11)	5	(6)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	8	(3)	5
Amortization of Actuarial Loss	O&M Expense	(8)	3	(5)	(22)	8	(14)

Total Pension and OPEB Plans		(5)	2	(3)	(14)	5	(9)	
Available-for-Sale Securities								
Realized Gains	Other Income	47	(24)	23	105	(54)	51	
Realized Losses	Other Deductions	(5)	2	(3)	(15)	7	(8)	
OTTI	OTTI	(10)	5	(5)	(14)	7	(7)	
Total Available-for-Sale Securities		32	(17)	15	76	(40)	36	
Total		$28	$(15)	$13	$51	$(30)	$21	

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Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2015			Nine Months Ended September 30, 2015		
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	$—	$—	$—	$17	$(7)	$10
Total Cash Flow Hedges		—	—	—	17	(7)	10
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	9	(3)	6
Amortization of Actuarial Loss	O&M Expense	(15)	6	(9)	(45)	18	(27)
Total Pension and OPEB Plans		(12)	5	(7)	(36)	15	(21)
Available-for-Sale Securities							
Realized Gains	Other Income	14	(7)	7	47	(24)	23
Realized Losses	Other Deductions	(11)	5	(6)	(24)	12	(12)
OTTI	OTTI	(30)	15	(15)	(45)	22	(23)
Total Available-for-Sale Securities		(27)	13	(14)	(22)	10	(12)
Total		$(39)	$18	$(21)	$(41)	$18	$(23)

Power		Amounts Reclassified from Accumulated Other Comprehensive Income (Loss) to Income Statement					
		Three Months Ended September 30, 2014			Nine Months Ended September 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	$1	$—	$1	$(11)	$5	$(6)
Total Cash Flow Hedges		1	—	1	(11)	5	(6)
Pension and OPEB Plans							
Amortization of Prior Service (Cost) Credit	O&M Expense	3	(1)	2	7	(3)	4
Amortization of Actuarial Loss	O&M Expense	(6)	2	(4)	(18)	7	(11)
Total Pension and OPEB Plans		(3)	1	(2)	(11)	4	(7)

Available-for-Sale Securities								
Realized Gains	Other Income	45	(23)	22	101	(52)	49	
Realized Losses	Other Deductions	(2)	1	(1)	(12)	6	(6)	
OTTI	OTTI	(10)	5	(5)	(14)	7	(7)	
Total Available-for-Sale Securities		33	(17)	16	75	(39)	36	
Total		$31	$(16)	$15	$53	$(30)	$23	

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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 September 30,				Nine Months Ended September 30,			
	2015		2014		2015		2014	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Net Income	$439	$439	$444	$444	$1,370	$1,370	$1,042	$1,042
EPS Denominator (Millions)								
Weighted Average Common Shares Outstanding	505	505	506	506	505	505	506	506
Effect of Stock Based Compensation Awards	—	3	—	1	—	3	—	1
Total Shares	505	508	506	507	505	508	506	507
EPS								
Net Income	$0.87	$0.87	$0.88	$0.87	$2.71	$2.70	$2.06	$2.05

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	2015	2014	2015	2014
Per Share	$0.39	$0.37	$1.17	$1.11
In Millions	$198	$187	$592	$561

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Note 16. Financial Information by Business Segments

	PSE&G	Power	Other (A)	Eliminations (B)	Consolidated
	Millions				
Three Months Ended September 30, 2015					
Total Operating Revenues	$1,766	$1,096	$120	$(294)	$2,688
Net Income (Loss)	222	206	11	—	439
Gross Additions to Long-Lived Assets	716	310	13	—	1,039
Nine Months Ended September 30, 2015					
Total Operating Revenues	$5,234	$3,846	$326	$(1,269)	$8,137
Net Income (Loss)	631	707	32	—	1,370
Gross Additions to Long-Lived Assets	1,946	797	39	—	2,782
Three Months Ended September 30, 2014					
Total Operating Revenues	$1,655	$1,138	$123	$(275)	$2,641
Net Income (Loss)	200	222	22	—	444
Gross Additions to Long-Lived Assets	497	188	8	—	693
Nine Months Ended September 30, 2014					
Total Operating Revenues	$5,235	$3,824	$359	$(1,305)	$8,113
Net Income (Loss)	565	440	37	—	1,042
Gross Additions to Long-Lived Assets	1,493	414	15	—	1,922
As of September 30, 2015					
Total Assets	$22,909	$12,314	$2,775	$(1,574)	$36,424
Investments in Equity Method Subsidiaries	$—	$116	$1	$—	$117
As of December 31, 2014					
Total Assets	$22,223	$12,046	$2,799	$(1,735)	$35,333
Investments in Equity Method Subsidiaries	$—	$121	$2	$—	$123

(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 PSE&G and Power. 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 PSE&G and Power, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between PSE&G and Power, see Note 17. Related-Party Transactions.

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Note 17. Related-Party Transactions

The following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

PSE&G

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
Related-Party Transactions	2015	2014	2015	2014
	Millions			
Billings from Affiliates:				
Billings from Power primarily through BGS and BGSS (A)	$294	$280	$1,287	$1,308
Administrative Billings from Services (B)	66	59	197	183
Total Billings from Affiliates	$360	$339	$1,484	$1,491

Related-Party Transactions	As of September 30, 2015	As of December 31, 2014
	Millions	
Receivable from PSEG (C)	$7	$274
Payable to Power (A)	$158	$313
Payable to Services (B)	50	66
Accounts Payable—Affiliated Companies	$208	$379
Working Capital Advances to Services (D)	$33	$33
Long-Term Accrued Taxes Payable	$165	$116

Power

The financial statements for Power include transactions with related parties presented as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Related-Party Transactions	2015	2014	2015	2014
	Millions			
Billings to Affiliates:				
Billings to PSE&G primarily through BGS and BGSS (A)	$294	$280	$1,287	$1,308
Billings from Affiliates:				
Administrative Billings from Services (B)	$44	$41	$135	$129

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Related-Party Transactions	As of September 30, 2015	As of December 31, 2014
	Millions	
Receivables from PSE&G (A)	$158	$313
Payable to Services (B)	$26	$23
Payable to PSEG (C)	91	95
Accounts Payable—Affiliated Companies	$117	$118
Short-Term Loan Due (to) from Affiliate (E)	$865	$584
Working Capital Advances to Services (D)	$17	$17
Long-Term Accrued Taxes Payable	$54	$41

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

(E) 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.

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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 tables present 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 September 30, 2015					
Operating Revenues	$—	$1,084	$37	$(25)	$1,096
Operating Expenses	3	692	35	(25)	705
Operating Income (Loss)	(3)	392	2	—	391
Equity Earnings (Losses) of Subsidiaries	220	(2)	3	(218)	3
Other Income	10	26	—	(11)	25
Other Deductions	—	(14)	—	—	(14)
Other-Than-Temporary Impairments	—	(30)	—	—	(30)
Interest Expense	(28)	(8)	(5)	11	(30)
Income Tax Benefit (Expense)	7	(148)	2	—	(139)
Net Income (Loss)	$206	$216	$2	$(218)	$206
Comprehensive Income (Loss)	$184	$187	$2	$(189)	$184
Nine Months Ended September 30, 2015					
Operating Revenues	$—	$3,811	$144	$(109)	$3,846
Operating Expenses	7	2,610	135	(109)	2,643
Operating Income (Loss)	(7)	1,201	9	—	1,203
Equity Earnings (Losses) of Subsidiaries	755	(4)	11	(751)	11
Other Income	33	111	—	(35)	109
Other Deductions	(1)	(31)	—	—	(32)
Other-Than-Temporary Impairments	—	(45)	—	—	(45)
Interest Expense	(90)	(24)	(15)	35	(94)
Income Tax Benefit (Expense)	17	(463)	1	—	(445)
Net Income (Loss)	$707	$745	$6	$(751)	$707
Comprehensive Income (Loss)	$690	$707	$6	$(713)	$690
Nine Months Ended September 30, 2015					
Net Cash Provided By (Used In) Operating Activities	$435	$1,826	$66	$(769)	$1,558
Net Cash Provided By (Used In) Investing Activities	$(656)	$(1,382)	$(303)	$1,191	$(1,150)
Net Cash Provided By (Used In) Financing Activities	$221	$(446)	$245	$(422)	$(402)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
Three Months Ended September 30, 2014					
Operating Revenues	$—	$1,125	$36	$(23)	$1,138
Operating Expenses	3	772	32	(22)	785
Operating Income (Loss)	(3)	353	4	(1)	353
Equity Earnings (Losses) of Subsidiaries	225	(1)	4	(224)	4
Other Income	9	55	—	(8)	56
Other Deductions	(3)	(4)	—	1	(6)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(24)	(10)	(4)	7	(31)
Income Tax Benefit (Expense)	18	(161)	(1)	—	(144)
Net Income (Loss)	$222	$222	$3	$(225)	$222
Comprehensive Income (Loss)	$195	$191	$3	$(194)	$195
Nine Months Ended September 30, 2014					
Operating Revenues	$—	$3,781	$118	$(75)	$3,824
Operating Expenses	12	3,079	106	(75)	3,122
Operating Income (Loss)	(12)	702	12	—	702
Equity Earnings (Losses) of Subsidiaries	459	(4)	11	(455)	11
Other Income	25	135	—	(25)	135
Other Deductions	(7)	(18)	—	—	(25)
Other-Than-Temporary Impairments	—	(14)	—	—	(14)
Interest Expense	(79)	(23)	(14)	24	(92)
Income Tax Benefit (Expense)	54	(329)	(2)	—	(277)
Net Income (Loss)	$440	$449	$7	$(456)	$440
Comprehensive Income (Loss)	$432	$433	$7	$(440)	$432
Nine Months Ended September 30, 2014					
Net Cash Provided By (Used In) Operating Activities	$471	$1,252	$53	$(666)	$1,110
Net Cash Provided By (Used In) Investing Activities	$187	$(559)	$(24)	$70	$(326)
Net Cash Provided By (Used In) Financing Activities	$(652)	$(693)	$(29)	$596	$(778)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
As of September 30, 2015					
Current Assets	$4,678	$1,786	$134	$(4,374)	$2,224
Property, Plant and Equipment, net	82	6,390	1,435	—	7,907
Investment in Subsidiaries	4,555	349	—	(4,904)	—
Noncurrent Assets	264	1,962	133	(176)	2,183
Total Assets	$9,579	$10,487	$1,702	$(9,454)	$12,314
Current Liabilities	$1,581	$3,595	$772	$(4,374)	$1,574
Noncurrent Liabilities	458	2,563	355	(176)	3,200
Long-Term Debt	1,691	—	—	—	1,691
Member's Equity	5,849	4,329	575	(4,904)	5,849
Total Liabilities and Member's Equity	$9,579	$10,487	$1,702	$(9,454)	$12,314
As of December 31, 2014					
Current Assets	$4,263	$2,037	$150	$(4,091)	$2,359
Property, Plant and Equipment, net	81	6,265	1,169	—	7,515
Investment in Subsidiaries	4,516	120	—	(4,636)	—
Noncurrent Assets	278	1,952	137	(195)	2,172
Total Assets	$9,138	$10,374	$1,456	$(8,922)	$12,046
Current Liabilities	$883	$3,606	$786	$(4,091)	$1,184
Noncurrent Liabilities	454	2,442	360	(195)	3,061
Long-Term Debt	2,243	—	—	—	2,243
Member's Equity	5,558	4,326	310	(4,636)	5,558
Total Liabilities and Member's Equity	$9,138	$10,374	$1,456	$(8,922)	$12,046

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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), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power 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:

- 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, and
- 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.

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 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 2014 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 Executive Overview of 2014 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2015 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 2014 Form 10-K.

EXECUTIVE OVERVIEW OF 2015 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 and other infrastructure projects, and
- Maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the three months and nine months ended September 30, 2015 and 2014 are presented as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Earnings	2015	2014	2015	2014
	Millions			
PSE&G	$222	$200	$631	$565
Power (A)	206	222	707	440
Other (B)	11	22	32	37
PSEG Net Income	$439	$444	$1,370	$1,042
PSEG Net Income Per Share (Diluted)	$0.87	$0.87	$2.70	$2.05

(A) Includes an after-tax insurance recovery for Superstorm Sandy of $102 million in the nine months ended September 30, 2015. See Item 1. Note 8. Commitments and Contingent Liabilities.

(B) 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 September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	Millions, after tax			
NDT Fund Income (Expense) (A)	$(14)	$17	$(11)	$40
Non-Trading MTM Gains (Losses)	$50	$36	$58	$(138)

(A) NDT Fund Income (Expense) includes the realized gains and losses, 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 Operation and Maintenance (O&M) Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense.

Our $5 million decrease in Net Income for the three months ended September 30, 2015 was driven primarily by:

- lower net realized gains and higher other-than-temporary impairments related to the NDT Fund, and
- higher maintenance costs related to the earlier start in 2015 of the planned annual outage of our Peach Bottom Unit 3 nuclear facility and higher pension and OPEB costs.

These decreases were largely offset by

- higher revenues due to increased investments in transmission projects, and
- higher MTM gains.

Our $328 million increase in Net Income for the nine months ended September 30, 2015 was driven primarily by:

- MTM gains in 2015 as compared to MTM losses in 2014,
- higher volumes of electricity sold under wholesale load contracts and under the BGS contract, the latter at higher average prices,
- lower generation costs due to lower fuel costs,

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- higher revenues due to increased investments in transmission projects, and
- insurance recoveries of Superstorm Sandy costs, primarily at Power.

These year-to date increases were partially offset by

- lower realized gains and higher other-than-temporary impairments related to the NDT Fund,
- higher planned outage costs at our nuclear plants and higher pension and OPEB costs, and
- higher Depreciation Expense largely related to increased investments in transmission and distribution projects and a higher depreciable nuclear and fossil asset base.

At PSE&G, our regulated utility, we continued to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers. Effective January 1, 2015, PSE&G's formula rate increased our annual transmission revenues by approximately $182 million. Each year, transmission revenues are filed based on estimated data and subject to true up with actual current year data. The true-up adjustment for 2015, which will be filed in the Spring of 2016, will primarily include the impact on rate base due to the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 annual revenue increase by approximately $21 million. In October 2015, we filed our 2016 Annual Formula Rate Update with the Federal Energy Regulatory Commission (FERC), which will provide $146 million in increased annual transmission revenues effective January 1, 2016.

Over the past few years, these types of investments have altered the business mix of our overall results of operations to reflect a higher percentage contribution by PSE&G.

Power’s results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2015. Power manages these contracts for the benefit of PSE&G’s customers through the basic gas supply service (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 make third party sales and supply gas to its generating units in New Jersey.

Gas prices have remained relatively low this year as a result of the expansion of shale gas production, primarily in the Marcellus/Utica regions. These low prices benefit PSE&G’s gas customers and provide a low cost fuel supply for Power’s combined cycle units. However, they have also resulted in a decline in power prices. Our contractual hedges currently in place have helped mitigate some of the effects of low prices this year and for 2016. However, as these arrangements expire and new hedges are set at lower price levels, our margins will be impacted. A sustained continuation of low prices could have an adverse impact on the earnings from our nuclear and coal-fired units.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

FERC’s rule under Order 1000 altered the right of first refusal (ROFR) previously held by incumbent utilities to build transmission within their respective service territories, creating the potential that new transmission projects in our service territory could be assigned to third parties rather than PSE&G. Order 1000 also presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM Interconnection, L.L.C. (PJM) initiated a solicitation process in which we participated to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem and Hope Creek nuclear generation facilities. In April 2015, the PJM staff advised stakeholders that it intended to recommend a transmission project that would primarily be awarded to another entity, but that a portion would be assigned to PSE&G. We subsequently filed comments with the PJM Board of Managers (PJM Board) identifying what we believed were deficiencies in the PJM staff recommendation. In July 2015, the PJM Board approved the PJM staff's recommendation and in August 2015, PJM provided notice to PSE&G of its designation for construction responsibility with respect to three components of the project, estimated by PJM to cost approximately $126 million. PSE&G is currently in discussions with PJM regarding the accuracy of this

estimate given the complexities associated with construction work at Artificial Island. See Part II. Item 5. Other Information—Transmission Regulation—Transmission Policy Developments for additional information.

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Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which FERC had determined that demand response (DR) providers should receive full market compensation for power and held that FERC has no jurisdiction over DR. In October 2015, the U.S. Supreme Court heard oral arguments on this case. Although a reversal by the U.S. Supreme Court of the federal court's decision regarding FERC's lack of jurisdiction is not expected to have significant impacts on capacity markets, a decision that upholds such decision could have a material impact on capacity market outcomes.

In a separate development of significance to the wholesale capacity market, in December 2014 PJM filed at FERC its proposal for a capacity performance product to include generators, DR and energy efficiency providers who would need to certify their availability during emergency conditions, as a supplement to base capacity. The proposal included enhanced performance-based incentives and penalties. In June 2015, FERC conditionally accepted the proposal. PJM commenced the auction on August 10, 2015 and announced the auction results on August 21, 2015. Power cleared 8,634 MW of its generating capacity at an average price of $214.72 MW-day for the 2018-2019 delivery period. Of the cleared capacity, Power believes that nearly all is compliant with PJM's CP requirements. In the two prior capacity auctions covering the 2016-2017 and 2017-2018 delivery years, Power cleared approximately 8,700 MW at average prices of $172 MW-day and $177 MW-day, respectively. The capacity that Power cleared for the 2018-2019 delivery year included Sewaren 7 and Keys Energy Center generation plants. See Other Developments below for additional details about our construction of these two new projects. We believe that this pricing adequately reflects the increased costs that could result from operating under more stringent rules for generation availability. No assurances can be given that similar pricing will continue in future auctions.

Applications for rehearing of FERC's capacity performance order are pending. See Part II, Item 5. Other Information—Capacity Market Issues—PJM for additional information.

We have also been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. A recent development which we view as positive involves a September 2015 FERC notice of proposed rulemaking on two issues: aligning settlements with dispatch intervals (more granular “5-minute pricing” in real-time markets) and improving real-time scarcity pricing. Comments made by FERC commissioners stressed these two items are intended to be the first of a series of steps FERC will take on energy price formation in the future. See Part II, Item 5. Other Information—Price Formation Initiatives for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. In particular, the EPA’s 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. As adopted by the EPA, the rule requires that cooling water intake structures reflect the best technology available for minimizing environmental impacts. 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 power facilities on a case by case basis. In June 2015, the New Jersey Department of Environmental Protection (NJDEP) issued a draft New Jersey Pollutant Discharge Elimination Systems (NJPDES) permit governing cooling water intake structures for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with required system modifications. The draft permit was subject to a sixty-day public notice and comment period. The NJDEP may make revisions before issuing the final permit expected during the first half of 2016. We participated in the NJDEP’s August 2015 public hearing and submitted comments on the draft permit in September 2015. See Item 1. Note 8. Commitments and Contingent Liabilities for further information.

The EPA’s greenhouse gas (GHG) emissions regulations are also of potential consequence to our results. In October 2015, the EPA published the Clean Power Plan (CPP), a GHG emissions regulation under the Clean Air Act (CAA) for existing power plants. The regulation establishes state-specific emission targets based on implementation of the

best systems of emission reduction. Each state must submit a compliance plan to the EPA by September 6, 2016 or seek a two-year extension to September 6, 2018. We continue to work with FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations. The EPA, FERC and the U.S. Department of Energy have announced that they plan to meet at least quarterly to evaluate states' plans and identify reliability concerns so adjustments can be made before the final plans are submitted. The agencies are engaging various stakeholders, including the Regional Transmission Operators/Independent System Operators. The agencies will continue to meet after the states' plans are in effect to assess if revisions are required. See Part II, Item 5. Other Information—CO_2 Regulation Under the 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 regulations if and when they are implemented. In addition, state environmental regulations governing emissions from power plants also have a significant

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impact on our operations. In the second quarter of 2015, we retired 1,545 MW of fully depreciated combustion turbine capacity that would not be able to comply with the more stringent emission standards for high electric demand day units (HEDD) under the New Jersey HEDD regulations for nitrous oxide, which will reduce capacity revenues for this year.

Other Developments

In the first nine months of 2015, we continued to make investments and seek recovery on such investments made to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the New Jersey Board of Public Utilities (BPU) in 2014. As approved, the Energy Strong program provides for $1.2 billion of investment, with 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, through an accelerated recovery mechanism. We will seek recovery of up to $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017.

In September 2015, we reached a settlement in principle with the BPU Staff and the New Jersey Division of Rate Counsel regarding PSE&G’s Gas System Modernization Program (GSMP) through which, if approved, we will invest $905 million over the next three years to modernize PSE&G's gas systems. The settlement in principle provides for cost recovery at a 9.75% rate of return on equity on the first $650 million of the investment through an accelerated recovery mechanism. Under the settlement in principle, PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case, which is to be filed no later than November 1, 2017. For additional information, see Part II, Item 5. Other Information—Gas System Modernization Program.

In August 2015, we announced our plan to construct Sewaren 7, a new 540 MW duel-fueled combined cycle generating plant in Woodbridge, New Jersey scheduled to be in-service for the summer of 2018 at an estimated investment of $625 million - $675 million. The Sewaren 7 plant will replace Sewaren Units 1, 2, 3 and 4.

In June 2015, we acquired a development project to construct a 755 MW gas-fired combined cycle generating station (Keys Energy Center) in Maryland with completion expected in 2018 at an estimated investment of $825 million - $875 million.

The preliminary non-public staff investigation initiated by FERC into Power's discovery and investigation of (i) incorrect calculations for certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market and (ii) differences in the quantity of energy that Power offered into the energy market for its fossil peaking units from the amount for which Power was compensated in the capacity market for those units continues. Power has an ongoing process of implementing improved procedures to help mitigate the risk of similar issues occurring in the future. This investigation could result in 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 this matter, or the applicability of mitigating factors. For more detailed information, refer to Item 1. 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 nine months of 2015, our

- total nuclear fleet achieved an average capacity factor of 92%,
- nuclear output increased by 2.7% and combined cycle output by 14.9% as compared to the same period in 2014, and
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 42.5 TWh while addressing unit outages and balancing fuel availability and price volatility.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2015 as we

- had cash flow from operations of $3.2 billion as of September 30, 2015,
- maintained solid investment grade credit ratings,

- extended the expiration dates for approximately $2.0 billion of five-year credit facilities for PSEG, PSE&G and Power from 2018 to 2020, and
- increased our indicated annual dividend for 2015 to $1.56 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, Energy Strong distribution program, Keys Energy Center and other planned projects, as well as our GSMP, without the issuance of new equity.

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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 2015, in addition to our acquisition of the Keys Energy Center and clearance of Sewaren 7 in the 2018/2019 capacity auction, each of which is under construction, we

- placed into service the final phase of our 500 kV Susquehanna-Roseland and 230 kV Mickleton-Gloucester-Camden transmission projects,
- made additional investments in transmission infrastructure projects,
- secured approval to extend three Energy Efficiency Economic Stimulus subprograms to allow for additional capital expenditures and administrative expenses to provide energy efficiency assistance to hospitals, healthcare facilities and residential multi-family housing units,
- continued to execute our existing BPU-approved utility programs,
- completed the power ascension for the extended power uprate at our co-owned Peach Bottom 2 nuclear station,
- completed installation of equipment to increase output and improve efficiency at our Bergen 2 combined cycle gas unit similar to our 2014 installation at our Linden plant, and
- placed into service a 13 MWdc solar energy facility near Waldorf, Maryland and acquired and placed into service a 25 MWdc solar energy facility near San Francisco, California.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-moving economy and a cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business 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 manage our energy obligations and re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program, proposed GSMP 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,
- effectively manage construction of our Keys Energy Center, Sewaren 7 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system and manage LIPA's fuel supply and generation dispatch obligations.

For 2015 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 behaviors and demand, the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development 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, PSE&G and Power, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 1. Note 17. Related-Party Transactions.

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$2,688	$2,641	$47	2	$8,137	$8,113	$24	—
Energy Costs	815	863	(48)	(6)	2,577	3,008	(431)	(14)
Operation and Maintenance	746	714	32	4	2,170	2,370	(200)	(8)
Depreciation and Amortization	313	318	(5)	(2)	960	919	41	4
Income from Equity Method Investments	3	3	—	—	10	10	—	—
Other Income and (Deductions)	33	66	(33)	(50)	135	154	(19)	(12)
Other-Than-Temporary Impairments	30	10	20	N/A	45	14	31	N/A
Interest Expense	96	100	(4)	(4)	291	291	—	—
Income Tax Expense	285	261	24	9	869	633	236	37

The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$1,766	$1,655	$111	7	$5,234	$5,235	$(1)	—
Energy Costs	740	668	72	11	2,176	2,278	(102)	(4)
Operation and Maintenance	391	366	25	7	1,171	1,190	(19)	(2)
Depreciation and Amortization	231	238	(7)	(3)	712	682	30	4
Other Income (Deductions)	22	14	8	57	57	41	16	39
Interest Expense	67	71	(4)	(6)	203	206	(3)	(1)
Income Tax Expense	137	126	11	9	398	355	43	12

Three Months Ended September 30, 2015 as Compared to 2014

Operating Revenues increased $111 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $67 million due primarily to increases in transmission and electric distribution revenues.

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Transmission revenues were $41 million higher due to increases resulting primarily from increased capital investments.

- Electric distribution revenues increased $29 million due primarily to higher sales volumes of $24 million, higher Green Program Recovery Charges (GPRC) of $3 million and $2 million due to the roll in of Energy Strong into base rates effective September 1, 2015.

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- Gas distribution revenues decreased $3 million due primarily to lower delivery volume.

Commodity Revenue increased $72 million as a result of higher Electric revenues partially offset by lower Gas revenues. Commodity revenue for both electric and gas is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of basic generation service (BGS) and Basic Gas Supply Service (BGSS) to retail customers.

- Electric revenues increased $81 million due primarily to an $83 million or 16% increase in BGS revenues due to higher sales volumes and $2 million of higher revenues from collections of Non-Utility Generation Charges (NGC). These increases were partially offset by a $4 million reduction in revenues due to lower volumes on Non-Utility Generation (NUG) energy sold at lower prices.
- Gas revenues decreased $9 million due primarily to $11 million in lower BGSS prices, partially offset by $2 million in higher prices.

Clause Revenues decreased $28 million due primarily to lower Securitization Transition Charges (STC) of $28 million, lower Solar Pilot Recovery Charges (SPRC) of $3 million, and lower Margin Adjustment Clause Revenue of $1 million, partially offset by higher Societal Benefit Charges (SBC) of $4 million. The changes in the STC, SPRC, MAC and SBC amounts are 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 STC, SPRC, MAC or SBC collections.

Other Operating Revenues experienced no material change.

Operating Expenses

Energy Costs increased $72 million due to higher Electric costs partially offset by lower Gas costs. This is entirely offset by decreased Commodity Revenue.

- Electric costs increased $81 million or 14% due to $45 million of higher BGS and NUG prices and $68 million in higher BGS volumes. BGS volumes increased due to higher sales volumes due to warmer weather and reverse customer migration. These increases were partially offset by $19 million of decreased deferred cost recovery and $13 million of lower NUG volumes.
- Gas costs decreased $9 million or 11% due to $11 million in lower prices, partially offset by $2 million in higher volumes.

Operation and Maintenance increased $25 million, of which the most significant components were

- $10 million increase in pension and OPEB expenses,
- $7 million increase in transmission operating expenses,
- $8 million increase in other operating expenses, including $4 million in appliance service costs, $3 million in higher preventive maintenance and tree trimming and $1 million increase in general operating expenses,

partially offset by a $3 million decrease in costs related to a net decrease in SBC, MAC, GPRC, SPRC and STC. Due to the nature of the SBC, MAC, SPRC and STC clause mechanisms, these are entirely offset in revenue.

Depreciation and Amortization decreased $7 million due primarily to a decrease of $22 million in amortization of Regulatory Assets, partially offset by a $13 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects.

Other Income and (Deductions) increased $8 million due primarily to an increase in Allowance for Funds used During Construction (AFUDC).

Interest Expense decreased $4 million due primarily to partial redemption of securitization debt and clause interest, partially offset by net issuances of Medium Term Notes during 2015 and the latter half of 2014.

Income Tax Expense increased $11 million due primarily to higher pre-tax income.

Nine Months Ended September 30, 2015 as Compared to 2014

Operating Revenues decreased $1 million due to changes in delivery, commodity, clause and other operating revenues.

Delivery Revenues increased $178 million due primarily to increases in transmission and electric distribution revenues.

- Transmission revenues were $124 million higher due to increases resulting primarily from increased capital investments.

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- Electric distribution revenues increased $45 million due primarily to higher sales volumes of $37 million, an increase in Capital Stimulus Infrastructure Program (CIP) revenues of $5 million due to the inclusion of CIP II in base rates beginning in July 2014 and $3 million of higher revenues from GPRC.
- Gas distribution revenues increased $9 million due primarily to $16 million from higher sales volumes and an increase in CIP revenues of $2 million, partially offset by lower Weather Normalization Charges (WNC) revenue of $9 million due to colder weather in 2015 compared to 2014.

Commodity Revenue decreased $102 million due to lower Gas revenues offset partially by higher Electric revenues. Commodity revenue for both electric and gas is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Gas revenues decreased $209 million due primarily to lower BGSS prices of $290 million, of which $215 million was due to lower residential rates resulting from $133 million in residential bill credits and $82 million of lower commodity prices, partially offset by higher BGSS volumes of $81 million due to colder weather in 2015.
- Electric revenues increased $107 million due primarily to $140 million of higher net BGS revenues. BGS revenues increased $171 million or 13%, due to higher sales volumes, which were partially offset by $31 million due to lower BGS rates. The increase from BGS was partially offset by $33 million in lower revenues from lower collection of NGC and lower sales prices and volumes of NUG energy.

Clause Revenues decreased $75 million due primarily to lower MAC revenue of $24 million, lower STC of $24 million, lower SBC of $23 million and lower SPRC of $4 million. The changes in the MAC, STC, SBC 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 MAC, STC, SBC or SPRC collections.

Other Operating Revenues experienced no material change.

Operating Expenses

Energy Costs decreased $102 million due to lower Gas costs partially offset by higher Electric costs. This is entirely offset by decreased Commodity Revenue.

- Gas costs decreased $209 million or 27% due to a $290 million or 37% decline in prices, partially offset by $81 million or 10% in higher sales volumes due to colder than normal weather.
- Electric costs increased $107 million or 7% due to a $140 million or 11% increase in BGS volumes, due to reverse customer migration and higher sales volumes due to warmer weather and a $57 million increase due to higher BGS and NUG prices, partially offset by $69 million of decreased deferred cost recovery and $21 million in lower NUG sales volumes.

Operation and Maintenance decreased $19 million, of which the most significant components were

- a $63 million decrease in costs related primarily to a net decrease in SBC, MAC, GPRC, CIP, SPRC and STC. Due to the nature of the SBC, MAC, SPRC and STC clause mechanisms, these are entirely offset in revenues,
- storm insurance recovery proceeds of $10 million, and
- decreased injuries and damages of $6 million,
- partially offset by a $28 million increase in pension and OPEB expenses,
- increased transmission operating expenses of $10 million,
- $8 million of higher appliance service costs,
- increased bad debt expense of $6 million, and
- an $8 million increase in other general operating expenses.

Depreciation and Amortization increased $30 million due primarily to a $42 million increase in depreciation of additional plant in service related to increased investments in various transmission and distribution projects, offset by a decrease of $13 million in amortization of Regulatory Assets which is fully offset in Clause Revenues.

Other Income and (Deductions) increased $16 million due primarily to an increase in AFUDC.

Interest Expense decreased $3 million due primarily to partial redemption of securitization debt partially offset by net issuances of Medium Term Notes in 2015 and the latter half of 2014.

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Income Tax Expense increased $43 million due primarily to higher pre-tax income.

Power

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2015	2014	2015 vs. 2014		2015	2014	2015 vs. 2014	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$1,096	$1,138	$(42)	(4)	$3,846	$3,824	$22	1
Energy Costs	367	472	(105)	(22)	1,669	2,036	(367)	(18)
Operation and Maintenance	263	242	21	9	748	871	(123)	(14)
Depreciation and Amortization	75	71	4	6	226	215	11	5
Income from Equity Method Investments	3	4	(1)	(25)	11	11	—	—
Other Income (Deductions)	11	50	(39)	(78)	77	110	(33)	(30)
Other-Than-Temporary Impairments	30	10	20	N/A	45	14	31	N/A
Interest Expense	30	31	(1)	(3)	94	92	2	2
Income Tax Expense	139	144	(5)	(3)	445	277	168	61

Three Months Ended September 30, 2015 as Compared to 2014
Operating Revenues decreased $42 million due to changes in generation, gas supply and other operating revenues.

Gas Supply Revenues decreased $44 million due primarily to
- a decrease of $14 million in sales under the BGSS contract substantially comprised of lower average sales prices, and
- a decrease of $30 million due to lower average sales prices and volumes to third party customers.

Generation Revenues increased $3 million due primarily to
- an increase of $39 million due to higher volumes of electricity sold under our BGS contract at higher average prices, partially offset by a decrease of $27 million due primarily to lower volumes sold under the wholesale load contracts in the PJM and New England (NE) regions.

Other Operating Revenues decreased $1 million due to lower fees received from 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 decreased $105 million due to
- Generation costs decreased $59 million due primarily to lower fuel costs, reflecting lower average realized natural gas prices and the utilization of lower coal volumes at lower average realized prices, coupled with higher MTM gains in 2015. These decreased costs were partially offset by higher congestion costs in the PJM region.
- Gas costs decreased $46 million related to lower average gas inventory costs on both obligations under the BGSS contract and sales to third parties, coupled with lower volumes sold to third parties.

Operation and Maintenance increased $21 million due primarily to
- a net increase of $24 million at our nuclear facilities, primarily due to the start of the 2015 fall outage one month sooner than in 2014 at our 50%-owned Peach Bottom nuclear unit 3,

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- partially offset by a decrease of $5 million related to our fossil plants, largely due to higher costs incurred in 2014 for planned outages and maintenance.

Depreciation and Amortization increased $4 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) decreased $39 million due primarily to lower net realized gains from the NDT Fund.

Other-Than-Temporary Impairments increased $20 million due to an increase in impairments of the NDT Fund.

Interest Expense experienced no material change.

Income Tax Expense decreased $5 million in 2015 due primarily to lower pre-tax income.

Nine Months Ended September 30, 2015 as Compared to 2014

Operating Revenues increased $22 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $203 million due primarily to

- higher net revenues of $232 million due primarily to MTM gains in 2015 compared to MTM losses in 2014, partially offset by lower energy volumes sold in the NE region and lower average realized prices in the NE and New York (NY) regions,
- an increase of $78 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions, and
- an increase of $48 million due primarily to higher volumes of electricity sold under the BGS contract at higher average prices,
- partially offset by a decrease of $155 million due primarily to lower capacity revenues resulting from lower average auction prices coupled with lower ancillary and operating reserve revenues in the PJM region.

Gas Supply Revenues decreased $182 million due primarily to

- a net decrease of $86 million in sales under the BGSS contract, substantially comprised of lower average sales prices, partially offset by higher volumes due to colder average temperatures in the 2015 winter heating season, and
- a decrease of $96 million due to lower average sales prices and volumes to third party customers.

Other Operating Revenues increased $1 million due to higher fees received from 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 decreased $367 million due to

- Generation costs decreased $149 million due primarily to lower fuel costs, reflecting lower average realized natural gas and oil prices and the utilization of lower volumes of coal, coupled with MTM gains in 2015 as compared to MTM losses in 2014. These decreased costs were partially offset by the utilization of higher volumes of natural gas, coupled with higher congestion costs in the PJM region.
- Gas costs decreased $218 million related to lower average gas inventory costs on both obligations under the BGSS contract and sales to third parties, coupled with lower volumes sold to third parties. This was partially offset by higher volumes sold under the BGSS contract due to colder average temperatures during the 2015 winter heating season.

Operation and Maintenance decreased $123 million due primarily to

- a decrease of $145 million due to insurance recoveries related to Superstorm Sandy, and
- a net decrease of $48 million related to our fossil plants, largely due to higher costs incurred in 2014 for planned outage costs, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partially offset by planned outage costs in 2015 at our Bethlehem Energy Center generating plant and installation of upgraded technology at our combined cycle Bergen plant,

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partially offset by an increase of $48 million at our nuclear facilities, primarily due to higher planned outage costs at our 100%-owned Hope Creek and 50%-owned Peach Bottom 3 nuclear plants in 2015 as compared to our 57%-owned Salem nuclear unit 2 in 2014, and
a $22 million increase due to higher pension and OPEB costs.

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) decreased $33 million due primarily to lower net realized gains from the NDT Fund partially offset by a $28 million insurance recovery related to Superstorm Sandy.

Other-Than-Temporary Impairments increased $31 million due to an increase in impairments of the NDT Fund.

Interest Expense experienced no material change.

Income Tax Expense increased $168 million in 2015 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 nine months ended September 30, 2015, our operating cash flow increased $692 million as compared to the same period in 2014. The net change was due primarily to the net changes from PSE&G and Power as discussed below.

PSE&G

PSE&G's operating cash flow increased $175 million from $1,343 million to $1,518 million for the nine months ended September 30, 2015, as compared to the same period in 2014, due primarily to higher earnings, a $203 million reduction in tax payments, $37 million reduction in vendor payments and a $25 million decrease in prepayments. These amounts were partially offset by a decrease of $232 million due to a change in regulatory deferrals primarily driven by the return of prior year overcollections to customers for BGSS gas costs, Gas Weather Normalization charges and Non-Utility Generation charges.

Power

Power's operating cash flow increased $448 million from $1,110 million to $1,558 million for the nine months ended September 30, 2015, as compared to the same period in 2014, primarily due to higher earnings and a reduction in margin deposit requirements, partially offset by an increase of $197 million in tax payments.

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 $4.2 billion credit facilities are provided by a diverse bank group. As of September 30, 2015, our total available credit capacity was $3.9 billion.

As of September 30, 2015, no single institution represented more than 7% of the total commitments in our credit facilities.

As of September 30, 2015, 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. Our total credit facilities and available liquidity as of September 30, 2015 were as follows:

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Company/Facility	As of September 30, 2015 Total Facility Millions	Usage	Available Liquidity	Expiration Date	Primary Purpose
PSEG					
5-year Credit Facility	$500	$10	$490	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	—	500	Apr 2020	CP Support/Funding/Letters of Credit
Total PSEG	$1,000	$10	$990		
PSE&G					
5-year Credit Facility (B)	$600	$34	$566	Apr 2020	CP Support/Funding/Letters of Credit
Total PSE&G	$600	$34	$566		
Power					
5-year Credit Facility	$1,600	$201	$1,399	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	1,000	14	986	Apr 2020	Funding/Letters of Credit
Total Power	$2,600	$215	$2,385		
Total	$4,200	$259	$3,941		

(A)PSEG facility will be reduced by $23 million in April 2016 and $12 million in March 2018.
(B)PSE&G facility will be reduced by $29 million in April 2016 and $14 million in March 2018.
(C)Power facility will be reduced by $48 million in April 2016 and $24 million in March 2018.

Long-Term Debt Financing

PSE&G has $171 million of 6.75% Mortgage Bonds maturing in January 2016. Power has $300 million of 5.50% Senior Notes maturing in December 2015 and $303 million of 5.32% Senior Notes and $250 million of 2.75% Senior Notes maturing in September 2016.

For a discussion of our long-term debt transactions during 2015, see Item 1. Note 9. Changes in Capitalization.

Common Stock Dividends

On July 21, 2015, our Board of Directors approved a $0.39 per share common stock dividend for the third quarter of 2015. This reflects an indicated annual dividend rate of $1.56 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 Item 1. Note 15. Earnings Per Share (EPS) and Dividends.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's) and can be Stable, Negative, or Positive. 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 May 2015, Moody's published research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged. In May 2015, S&P published updated research reports and revised the outlook to stable from positive for PSEG's Corporate Credit Rating and Power's Senior Notes. S&P also affirmed the senior unsecured rating

of BBB+ at Power and the mortgage bond rating of A at PSE&G. In September 2015, Moody's published an updated research report on PSEG and revised the outlook to positive from stable. In September and October 2015, Fitch published full rating reports on PSEG and Power leaving ratings and outlooks unchanged. As of October 2015, PSEG has ended a contractual agreement with Fitch to provide credit rating services for PSEG, PSE&G and Power.

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

(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. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

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.

In September 2015, we reached a settlement in principle with the BPU Staff and the New Jersey Division of Rate Counsel regarding our GSMP, through which, if approved, we will invest $905 million over the next three years to modernize PSE&G’s gas systems.

In June 2015, we acquired a development project to construct a 755 MW gas-fired combined cycle generating station in Maryland (Keys Energy Center). We plan to start constructing this year with expected completion in 2018 at an estimated investment of $825 million - $875 million.

In August 2015, we announced our plan to construct Sewaren 7, a new 540 MW duel-fueled combined cycle generating plant in Woodbridge, New Jersey scheduled to be in-service for the summer of 2018 at an estimated investment of $625 million - $675 million.

The aforementioned estimated project expenditures related to the GSMP at PSE&G and the Maryland and Woodbridge, New Jersey projects at Power are not included in the $8.7 billion three-year capital forecast table in our 2014 Form 10-K. There were no material changes to our projected capital expenditures at Services as compared to amounts disclosed in our 2014 Form 10-K.

PSE&G

During the nine months ended September 30, 2015, PSE&G made capital expenditures of $1,946 million, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $82 million, which are included in operating cash flows.

Power

During the nine months ended September 30, 2015, Power made capital expenditures of $597 million, excluding $200 million for nuclear fuel, primarily related to various projects at its fossil and nuclear generation stations, including the new Maryland generating station noted above.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Item 1. Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The 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 July through September 2015, MTM VaR remained relatively stable between low of $8 million to high of $14 million at 95% confidence level. The range of VaR was narrower for the three months ended September 30, 2015 as compared with the year ended December 31, 2014.

	MTM VaR	
	Three Months Ended September 30, 2015	Year Ended December 31, 2014
	Millions	
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$10	$36
Average for the Period	$10	$30
High	$14	$195
Low	$8	$14
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$16	$56
Average for the Period	$15	$46
High	$23	$306
Low	$12	$22

See Item 1. 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, Public Service Electric and Gas Company and PSEG Power LLC. 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, Public Service Electric and Gas Company and PSEG Power LLC 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

There have been no changes in internal control over financial reporting that occurred during the third quarter of 2015 that have materially affected, or are reasonably likely to materially affect, each registrant's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For additional information regarding material legal proceedings, including updates to information reported in Item 3 of Part I of the 2014 Annual Report on Form 10-K, see see Part I, Item 1. 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 2014 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 third quarter of 2015.

Three Months Ended September 30, 2015	Total Number of Shares Purchased	Average Price Paid per Share
July 1 - July 31	—	$—
August 1- August 31	189,018	$42.23
September 1- September 30	20,000	$38.97

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ITEM 5. OTHER INFORMATION

Certain information reported in the 2014 Annual Report on Form 10-K is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2014 Annual Report on Form 10-K and the Quarterly Report on Form 10-Q for the quarters ended March 31, 2015 and June 30, 2015. References are to the related pages on the Forms 10-K and 10-Q as printed and distributed.

Federal Regulation

FERC

Regulation of Wholesale Sales—Generation/Market Issues

Capacity Market Issues—PJM

December 31, 2014 Form 10-K page 16, March 31, 2015 Form 10-Q page 69 and June 30, 2015 Form 10-Q page 78. The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity.

On December 12, 2014, PJM filed a proposal at FERC to implement a Capacity Performance (CP) mechanism. Under this mechanism, PJM created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. On June 9, 2015, FERC conditionally accepted the CP mechanism which will be phased in over the next few years, with the participation of both the CP product and a base product that has less rigorous performance obligations. The CP mechanism was implemented for the 2015 base residual auction (covering the 2018-2019 Delivery Year) which concluded on August 21, 2015. The CP product will be implemented fully for the 2020-2021 Delivery Year. Based upon the August 2015 base residual auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power but future impacts cannot be assured. Further, there may be requirements for additional investment and there are additional performance risks.

On June 30, 2015, a consumer coalition filed a complaint requesting that the load forecast that PJM was currently analyzing and updating to determine the amount of capacity it would procure in the 2016 base residual auction be implemented immediately for the upcoming 2015 transition auctions and base residual auction. FERC did not address the complaint prior to the auctions, effectively denying it.

Price Formation Initiatives

Power has been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. A recent development which we consider positive involves a September 17, 2015 FERC notice of proposed rulemaking on two issues: aligning settlements with dispatch intervals (more granular “5-minute pricing” in real-time markets) and improving real-time scarcity pricing. Comments made by FERC commissioners stressed these two items are intended to be the first of a series of steps FERC will take on energy price formation in the future.

Reactive Power Rates

In June 2015, Power submitted a tariff filing with FERC to increase Power’s rates for reactive supply and voltage control service from approximately $27 million per year to about $39 million per year. The rates were last adjusted in 2008 and since that time various generating units have been de-activated, activated or improved with the net impact supportive of an upward rate adjustment. FERC accepted Power’s rate filing increase to become effective in January 2016, subject to refund, hearing and settlement procedures. FERC also referred the filing to the FERC Office of Enforcement for its evaluation. Power has participated in two settlement conferences to date with the FERC trial staff.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)

December 31, 2014 Form 10-K page 18. In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. This federal court decision was subsequently challenged on appeal in the U.S. Third Circuit Court of

Appeals. The State of Maryland also took similar action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland and such decision was challenged in the U.S. Fourth Circuit Court of Appeals. Both appeals were denied, with the U.S. Fourth Circuit Court of Appeals (Fourth Circuit) denying the appeal regarding the State of Maryland’s action in June 2014 and the U.S. Third Circuit Court of Appeals denying the LCAPP appeal in September 2014. These denials have been challenged on appeal to the U.S. Supreme Court. In October 2015, the U.S. Supreme Court announced that it would consider the appeal of the Fourth Circuit's decision involving Maryland. The U.S. Supreme Court is expected to consider this case in 2016. We cannot predict the outcome of this appeal.

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Transmission Regulation—Transmission Policy Developments

December 31, 2014 Form 10-K page 18, March 31, 2015 Form 10-Q page 70 and June 30, 2015 Form 10-Q page 78. In April 2013, PJM initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island off the shore of New Jersey. In April 2015, the PJM staff advised stakeholders that it intended to recommend a transmission project to the PJM Board of Managers consisting of various components to be constructed by LS Power, PSE&G and Potomac Holding Company. On July 29, 2015, the PJM Board approved the PJM staff's recommendation. In August 2015, PJM sent PSE&G a Construction Responsibility Letter (to which PSE&G will be responding on November 9) awarding PSE&G three components of the project, estimated by PJM to cost approximately $126 million. PSE&G is currently in discussions with PJM regarding the accuracy of this estimate given the complexities associated with construction work at Artificial Island. In a related matter, FERC denied a complaint filed by PSE&G contending that PJM had failed to follow its rules during the Artificial Island solicitation process. PSE&G, however, continues to work with both PJM and its stakeholders to improve the rules governing open window processes in PJM.

In November 2014, Con Edison had brought a complaint against PJM at FERC challenging PJM's allocation of costs for two PSE&G projects in northern New Jersey, including the Bergen-Linden Corridor Project (BLC). In June 2015, FERC issued an order dismissing the complaint. Con Edison and a merchant generator have sought judicial review of certain aspects of FERC’s order and Con Edison has filed a rehearing request with FERC.

There have been developments on several additional matters involving cost allocation issues. In May 2015 and as amended in July 2015, a merchant transmission operator filed a complaint against PJM challenging PJM’s allocation of costs for four PSE&G projects, including BLC. PSE&G filed opposition to the complaint and the matter is currently pending at FERC. In August 2015, the Delaware Public Service Commission and the Maryland Public Service Commission filed a complaint against PJM and certain transmission owners that have voting rights over cost allocation and rate design, including PSE&G, alleging that PJM tariff provisions allocate an excessive share of the Artificial Island project costs to them relative to the actual benefits of the project to residents of Delaware and Maryland. PSE&G intends to participate in a group filing of transmission owners that will oppose the complaint.

In June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. According to the complaint, PJM and certain transmission owners wrongfully inflated the scope and associated costs of mitigation work needed to accommodate the developer’s proposal in order to prevent it from pursuing its projects. Although not named as a respondent in the complaint, PSE&G is identified as one of the companies claimed to have been involved. In July 2015, PJM filed a response, which included a supporting affidavit from PSE&G, contesting the allegations. The matter is pending.

State Regulation

Gas System Modernization Program (GSMP)

March 31, 2015 Form 10-Q page 71. In September 2015, PSE&G reached a settlement in principle with the BPU Staff and the New Jersey Division of Rate Counsel regarding PSE&G’s GSMP through which, if approved, PSE&G will invest $905 million over the next three years to modernize its gas system. The settlement in principle will enable the utility to replace up to 510 miles of gas mains and 38,000 service lines over a three-year period, with cost recovery at a 9.75% rate of return on equity on the first $650 million of the investment through an accelerated recovery mechanism. Under the settlement in principle, PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case, which is to be filed no later than November 1, 2017.

Connecticut Rate Filing

June 30, 2015 Form 10-Q page 79. In June 2015, Power’s subsidiary PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority (PURA) for recovery of its costs and investment in its Connecticut-based peaking unit. Power requested 2016 revenues of $22 million. On October 22, 2015, PURA issued a Proposed Final Decision to approve the entirety of Power’s request. A Final Decision is expected to be issued on November 4, 2015.

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Environmental Matters

Air Pollution Control

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

December 31, 2014 Form 10-K page 23 and June 30, 2015 Form 10-Q page 79. In March 2013, Power filed a petition at the EPA challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued in January 2013. Among other things, the final EPA rule includes two exemptions that allow owners and operators of stationery emergency RICE to operate their engines without the installation and operation of emission controls (1) as part of an emergency DR program for 100 hours per year (100 hour exemption) or (2) as part of a financial arrangement with another entity per specified restrictions in non-emergency situations for 50 hours per year (50 hour exemption). This waiver of NESHAP standards results in disparate treatment of different generation technology types. In its appeal, Power sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. In August 2014, the EPA denied the March 2013 petition and in October 2014, Power appealed the EPA's denial to the D.C. Court. On May 1, 2015, the D.C. Court vacated the 100 hour exemption but thereafter granted a stay until May 1, 2016. On September 23, 2015, the D.C. Court granted the EPA's motion for voluntary remand of the 50 hour exemption provision to the EPA. While both provisions remain in place, the EPA will undergo proceedings to address the D.C. Court's orders. We believe that the impact of the D.C. Court's rulings would likely benefit Power's and its competitors' operations of their power generation peaking units.

Ozone Standard

March 31, 2015 Form 10-Q page 71. In December 2014, the EPA proposed a rule to lower the ambient air quality standard for the level of ozone in the atmosphere from 75 parts per billion (ppb) to a level in the range of 65-70 ppb. On October 1, 2015, the EPA finalized a standard of 70 ppb. To meet the new standard, the EPA and the states have to implement additional emission reduction strategies for NO_X and volatile organic compounds. Some portions of the Mid-Atlantic and New England states are not expected to be able to meet the new standard. Although the majority of our fossil generating units employ state-of-the-art NO_X emission controls, we cannot predict the outcome of this matter since new requirements of the EPA and the states are unknown at this time. A coal mining company has filed a petition for review with the D.C. Court to challenge the rule.

Climate Change

CO2 Regulation Under the Clean Air Act (CAA)

December 31, 2014 Form 10-K page 23, March 31, 2015 Form 10-Q page 72 and June 30, 2015 Form 10-Q page 80. On October 23, 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the CAA 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 three components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, and (iii) operation of incremental zero-emitting generation (renewables and nuclear). States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

Each state must submit a compliance plan to the EPA by September 6, 2016 or seek a two-year extension to September 6, 2018. States can comply using an emission rate-based plan (pounds CO_2/MWh) or a mass-based plan (tons). Compliance with the final rule is effective January 1, 2022.

The EPA, FERC and the U.S. Department of Energy announced that they plan to meet at least quarterly to evaluate states' plans and identify reliability concerns so adjustments can be made before the final plans are submitted. The agencies are engaging various stakeholders, including the Regional Transmission Operators/Independent System Operators. The agencies will continue to meet after the states' plans are in effect to assess if revisions are required.

On October 23, 2015, the EPA also published proposed federal implementation requirements for states that do not submit an EPA-approved compliance plan. Comments are due by January 21, 2016.

Numerous states, including New Jersey, and several industry groups have filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners are seeking a stay of the rule.

Water Pollution Control

Steam Electric Effluent Guidelines

December 31, 2014 Form 10-K page 24. On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power has two electric generation facilities, its dual-

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fuel (gas/coal) Mercer station in New Jersey and coal-fired Bridgeport Harbor station in Connecticut, that have bottom ash transport water discharges that are regulated under this rule. We are unable to predict if these new standards will have a material impact on Power's future capital requirements, financial condition or results of operations.

Cooling Water Intake Structure Regulation

December 31, 2014 Form 10-K page 25 and June 30, 2015 Form 10-Q page 80. On June 30, 2015, the NJDEP issued a draft permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit is subject to a sixty-day public notice and comment period. We participated in the NJDEP’s August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015. The NJDEP may make revisions before issuing the final permit expected in the first half of 2016. For additional information, see Part I, Item 1. Note 8. Commitments and Contingent Liabilities.

Waters of the United States

December 31, 2014 Form 10-K page 25 and June 30, 2015 Form 10-Q page 80. In April 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the U.S. under the Clean Water Act (CWA) programs in order to protect the streams and wetlands that form the foundation of the nation’s water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. The final rule was published on June 29, 2015 and we are reviewing it to determine the materiality of the impacts that might result from the final rule. Some states, including New Jersey, are subject to state requirements beyond those imposed under federal law. While we do not anticipate material impacts to projects in New Jersey, the new definition could impose requirements in other states and regions that could impact the development of renewables.

Various states, industry coalitions and environmental organizations have initiated legal action related to the provisions of the final rule. On October 9, 2015, the Sixth Circuit Court of Appeals issued a stay of the rule pending further court action.

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ITEM 6. EXHIBITS

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

a. PSEG:

Exhibit 10	Employment Agreement with Daniel J. Cregg. dated September 22, 2015
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 Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.1:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. PSE&G:

Exhibit 10	Employment Agreement with Daniel J. Cregg, dated September 22, 2015
Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.3:	Certification by Daniel J. Cregg Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. Power:

Exhibit 10	Employment Agreement with Daniel J. Cregg, dated September 22, 2015
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Daniel J. Cregg Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.4:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the U.S. Code
Exhibit 32.5:	Certification by Daniel J. Cregg 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/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2015

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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 ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2015

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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.

PSEG POWER LLC
(Registrant)

By: /S/ STUART J. BLACK
Stuart J. Black
Vice President and Controller
(Principal Accounting Officer)

Date: October 30, 2015