PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-K
February 27, 2017

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

FORM 10-K
(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2016
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 Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 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 973 430-7000 http://www.pseg.com	22-3663480

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
Public Service Electric and Gas Company	First and Refunding Mortgage Bonds 9 1/4% Series CC, due 2021 8%, due 2037 5%, due 2037	New York Stock Exchange
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange

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Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
Public Service Electric and Gas Company	Medium-Term Notes
PSEG Power LLC	Limited Liability Company Membership Interest

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Public Service Enterprise Group Incorporated	Yes x	No ¨
Public Service Electric and Gas Company	Yes x	No ¨
PSEG Power LLC	Yes x	No ¨

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ No x

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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 the 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 ¨	Non-accelerated filer ¨
Public Service Electric and Gas Company	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x
PSEG Power LLC	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x

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 x

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2016 was $23,504,828,537 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated’s sole class of Common Stock as of February 17, 2017 was 506,217,300.

As of February 17, 2017, 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 each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of	Documents Incorporated by Reference

Public Service Enterprise Group Incorporated	
III	Portions of the definitive Proxy Statement for the 2017 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 14, 2017, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities, and other filings we make with the United States Securities and Exchange Commission (SEC), including our subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations;
- the impact of pending rate case proceedings;
- regulatory, financial, environmental, health and safety risks associated with our ownership and operation of nuclear facilities;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;
- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;

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- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;
- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

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, results of operations or cash flows. 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 in light of new information or future events, 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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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K 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 are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 193.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC’s internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through two direct wholly owned subsidiaries, PSE&G and Power, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102.

We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid- Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries’ operating results. Below are descriptions of our two principal direct operating subsidiaries.

PSE&G	Power
A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory.	A Delaware limited liability company formed in 1999 as a result of the deregulation and restructuring of the electric power industry in New Jersey. It integrates the operations of its merchant nuclear and fossil generating assets with its wholesale power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions.
Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory.	Earns revenues from the generation and marketing of power and natural gas to hedge business risks and optimize the value of its portfolio of power plants, other contractual arrangements and oil and gas storage facilities. This is achieved primarily by selling power and transacting in natural gas and other energy-related products, on the spot market or using short-term or long-term contracts for physical and financial products. Also earns revenues from solar generation under long-term sales contracts for power and environmental products.
Has also implemented regulated demand response and energy efficiency programs and	

invested in solar generation within New Jersey.

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Our 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 our operating subsidiaries with certain management, administrative and general services at cost.

The following is a more detailed description of our business, including a discussion of our:

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

PSE&G

Our regulated transmission and distribution public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of
New Jersey's population resides.

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Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- Transmission—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the Federal Energy Regulatory Commission (FERC).
- Distribution—the delivery of electricity and gas to the retail customer's home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the New Jersey Board of Public Utilities (BPU).

The commodity portion of our utility business' electric and gas sales is managed by basic generation service (BGS) and basic gas supply service (BGSS) suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

We also earn margins through competitive services, such as appliance repair.

In addition to our current utility products and services, we have implemented several programs to invest in regulated solar generation within New Jersey, including:

- programs to help finance the installation of solar power systems throughout our electric service area, and
- programs to develop, own and operate solar power systems.

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information concerning these programs and the components of our tariffs, see Regulatory Issues—State Regulation and Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

How PSE&G Operates

We are a transmission owner in PJM Interconnection, L.L.C. (PJM) and we provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately 300 suburban and rural communities.

Transmission

We use formula rates for our transmission cost of service and investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula that considers Operation and Maintenance expenditures, rate base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our current approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information, see Regulatory Issues—Federal Regulation.

We continue to invest in transmission projects that are included for review in the FERC-approved PJM transmission expansion process. These projects focus on reliability improvements and replacement of aging infrastructure with anticipated capital spend of $4.1 billion for transmission in 2017-2019 as disclosed in Item 7. MD&A—Capital Requirements.

Distribution

PSE&G distributes gas and electricity to end users in our respective franchised service territories. Our approved rates, established in our most recent gas and electric base rate proceeding completed in mid-2010, provide for a ROE of 10.3% on distribution rate base. We are required to file our next distribution base rate case proceeding no later than November 1, 2017. The BPU has also approved a series of PSE&G infrastructure, energy efficiency and renewable energy investment programs with cost recovery through various clause mechanisms, with approved ROEs ranging from 9.75% to 10.3%. Our load requirements are split among residential, commercial and industrial customers, as described in the following table for 2016:

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	% of 2016 Sales	
Customer Type	Electric	Gas
Commercial	58%	37%
Residential	33%	59%
Industrial	9%	4%
Total	100%	100%

While our customer base has modestly increased since 2012, electric load has declined and gas load has increased as illustrated below:

Electric and Gas Distribution Statistics

	December 31, 2016				
	Number of Customers		Electric Sales and Gas Firm Sales (A)		Historical Annual Load Growth 2012-2016
Electric	2.2	Million	41,580	Gigawatt hours (GWh)	(0.4)%
Gas	1.8	Million	2,360	Million Therms	0.7%

(A) Excludes sales from Gas rate classes that do not impact margin, specifically Contract, Non-Firm Transportation, Cogeneration Interruptible and Interruptible Services.

The decline in electric sales is the result of changes in customer usage patterns, including conservation and more energy efficient appliances. Gas firm sales increased as a result of lower gas prices. Only gas firm sales impact margin.

During 2016, PSE&G, as part of its BPU-approved $1.2 billion Energy Strong Program, completed the replacement and modernization of 240 miles of low-pressure cast iron gas mains in or near flood areas. PSE&G continues to execute the Energy Strong Program to (1) upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage, and (2) with respect to PSE&G's gas system, upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones.

PSE&G also commenced modernizing its gas distribution system as part of our Gas System Modernization Program (GSMP) which was approved by the BPU in late 2015. The GSMP, through which we will invest $905 million over three years, will replace approximately 510 miles of cast iron and unprotected steel gas mains and about 38,000 unprotected steel service lines to homes and businesses, including the uprating of the mains to higher pressure. The mains and service lines will be replaced with stronger, more durable plastic piping, reducing the potential for leaks and release of methane gas. The new elevated pressure systems also enable the installation of excess flow valves that automatically shut off gas flow if a service line is damaged, and better support the use of high-efficiency appliances.

Solar Generation

In order to support New Jersey's Energy Master Plan and the state's renewable energy goals, we have undertaken two major solar initiatives at PSE&G, the Solar Loan Program and the Solar 4 All and Solar 4 All Extension Programs. Our Solar Loan Program provides solar system financing to our residential and commercial customers. The loans are repaid with cash or solar renewable energy certificates (SRECs). We sell the SRECs received through periodic auctions and use the proceeds to offset program costs. Our Solar 4 All Programs invest in utility-owned solar photovoltaic (PV) centralized solar systems installed on PSE&G property and third-party sites, including landfill facilities, and solar panels installed on distribution system poles in our electric service territory. We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell SRECs generated by the projects through the same periodic auction used in the loan program, the proceeds of which are used to offset program costs.

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Supply

Although commodity revenues make up almost 41% of our revenues, we make no margin on the default supply of electricity and gas since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type, which represents about 80% of PSE&G’s load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Residential Small Commercial Pricing (RSCP)). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-Commercial Industrial Energy Pricing (CIEP)).

We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jersey’s total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey’s electric distribution companies (EDCs). Once validated by the BPU, electricity prices for BGS service are set. Approximately one-third of PSE&G’s total BGS-RSCP eligible load is auctioned each year for a three-year term. For information on current prices, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G’s revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time and/or provide bill credits. See Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities for information on recent self-implementing credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not select third-party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A—Executive Overview of 2016 and Future Outlook.

Power

Through Power, we seek to produce low-cost electricity by efficiently operating our nuclear, coal, gas, oil-fired and renewable generation assets while balancing generation output, fuel requirements and supply obligations through energy portfolio management. Our commitments for load, such as BGS in New Jersey and other bilateral supply contracts, are backed by the generation we own and may be combined with the use of physical commodity purchases and financial instruments from the market to optimize the economic efficiency of serving the load. Power is a public utility within the meaning of the Federal Power Act and the payments it receives and how it operates are subject to FERC regulation. Power is also subject to certain regulatory requirements imposed by state utility commissions such as those in New York and Connecticut.

Products and Services

As a merchant generator and power marketer, our profit is derived from selling a range of products and services under contract to an array of customers including utilities, other power marketers, such as retail energy providers, or counterparties in the open market. These products and services may be transacted bilaterally or through exchange markets and include but are not limited to:

- Energy—the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh).

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- Capacity—distinct from energy, capacity is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch to produce energy when it is needed to meet system demand. Capacity is typically priced in dollars per MW for a given sale period (e.g. day or month).
- Ancillary Services—related activities supplied by generation unit owners to the wholesale market that are required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges collected from market participants.
- Congestion and Renewable Energy Credits—Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a transmission path. Renewable Energy Credits (RECs) are obtained through Power’s owned renewable generation or purchased in the open market. Electric suppliers of load are required to deliver a certain amount or percentage of their delivered power from renewable resources as mandated by applicable regulatory requirements.

Power also sells wholesale natural gas, primarily through a full-requirements BGSS contract with PSE&G to meet the gas supply requirements of PSE&G’s customers. On March 19, 2014, the BPU approved an extension of the long-term BGSS contract to March 31, 2019 and then year-to-year thereafter unless terminated by either party with a two year notice.

Approximately 45% of PSE&G’s peak daily gas requirements is provided from Power’s firm gas transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G’s requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply and propane. Based upon the availability of natural gas beyond PSE&G’s daily needs, Power sells gas to others and uses it for its generation fleet.

In addition to its nuclear and fossil generation fleet, Power owns and operates 326 MW direct current (dc) of PV solar generation facilities and has an additional 70 MW dc of PV solar generation in construction. Power has a 50% ownership interest in a 208 MW oil-fired generation facility in Hawaii.

The remainder of this section about Power covers our nuclear and fossil fleet in the Mid-Atlantic and Northeast regions which comprises the vast majority of Power’s operations and financial performance.

How Power’s Generation Operates

Nearly all of our generation capacity consists of nuclear and fossil generation (11,681 MW) that is located in the Northeast and Mid-Atlantic regions of the United States in some of the country’s largest and most developed electricity markets. For additional information see Item 2. Properties.

The map below shows the locations of our Northeast and Mid-Atlantic nuclear and fossil generation facilities and projects under construction:

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- Generation Capacity

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels. As of December 31, 2016, our fuel mix was comprised of 41% gas, 32% nuclear, 20% coal, 5% oil and 2% pumped storage. This fuel mix does not give effect to our previously announced decision to cease generation operations of the existing coal/gas units at our Hudson and Mercer generating stations on June 1, 2017. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2016 was approximately 52,000 GWh. The generation mix by fuel type in recent years has reflected the relatively more favorable price of natural gas compared to coal, making it more economical to run certain of our gas units in place of our coal units. The following table indicates the proportionate share of generating output by fuel type in 2016.

Generation by Fuel Type (A)	Actual 2016	
Nuclear:		
New Jersey facilities	36%	
Pennsylvania facilities	21%	
Fossil:		
Coal:		
Pennsylvania facilities	9%	
Connecticut facilities	—%	(B)
Coal and Natural Gas:		
New Jersey facilities	—%	(B)
Natural Gas and Oil:		
New Jersey facilities	24%	
New York facilities	10%	
Connecticut facilities	—%	(B)
Total	100%	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii which account for less than two percent of total generation.

(B) Less than one percent.

We are also executing the following growth projects which are included in the 2017-2019 capital spend of $1.3 billion for Fossil Growth Opportunities disclosed in Item 7. MD&A—Capital Requirements.

Major Growth Projects
As of December 31, 2016

Project	Location	Expected In-Service Date
Keys Energy Center gas-fired combined cycle generating station (755 MW)	Maryland	2018
Sewaren 7 dual-fueled combined cycle generating station (540 MW)	New Jersey	2018
Bridgeport Harbor 5 gas-fired combined cycle generating station (485 MW)	Connecticut	2019
Bethlehem Energy Center (BEC) combined cycle uprate (58 MW)	New York	2017/2018

- Generation Dispatch

Our generation units have historically been characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance.

- Base Load Units run the most and typically are called to operate whenever they are available. These units generally derive revenues from both energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the unit's "capacity factor," or the ratio of the actual output to the theoretical maximum output. In 2016, our base load capacity factors were as follows:

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Unit	2016 Capacity Factor
Nuclear	
Salem Unit 1	67.0%
Salem Unit 2	84.3%
Hope Creek	89.8%
Peach Bottom Unit 2	91.7%
Peach Bottom Unit 3	100.0%
Coal	
Keystone	68.4%
Conemaugh	61.7%

- Load Following Units' operating costs are generally higher per unit of output than for base load units due to the use of higher-cost fuels such as oil, natural gas and, in some cases, coal or lower overall unit efficiency. These units usually have more flexible operating characteristics than base load units which enable them to more easily follow fluctuations in load. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.
- Peaking Units run the least amount of time and in some cases may utilize higher-priced fuels. These units typically start very quickly in response to system needs. Costs per unit of output tend to be higher than for base load units given the combination of higher heat rates and fuel costs. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will generally dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system "load") is satisfied reliably. Base load units are dispatched first, with load following units next, followed by peaking units. It should be noted that the sustained lower pricing of natural gas over the past several years has resulted in changes in relative operating costs compared to historical norms, wherein some gas-fired generation is now able to displace some coal-fired generation. This change, combined with the addition of new, more efficient generation capacity, has altered the historical dispatch order of certain plants in the markets where we operate.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO may dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

Typically, the bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the LMP for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong or weak demand. Therefore, changes in the price of natural gas will often translate into changes in the wholesale price of electricity. This can be seen in the following graphs which present historical annual spot prices and forward calendar prices as averaged over each year at two liquid trading hubs.

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Historical data implies that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which we operate.

The prices reflected in the preceding graphs above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. As shown above, prices may vary by location resulting from congestion or other factors, such as the availability of natural gas from the Marcellus (Leidy) and other shale-gas regions These variations can be considerable. Concurrent with the development of regional shale gas, we have been increasing our purchases from the Marcellus/Utica shale gas regions and in 2016 they accounted for approximately 90% of the gas we procured. While these prices provide some perspective on past and future prices, the forward prices are volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

- Nuclear Fuel Supply—We have long-term contracts for nuclear fuel. These contracts provide for:
  - purchase of uranium (concentrates and uranium hexafluoride),
  - conversion of uranium concentrates to uranium hexafluoride,
  - enrichment of uranium hexafluoride, and
  - fabrication of nuclear fuel assemblies.

Our nuclear fuel contracts cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2018 and a significant portion through 2021.

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- Coal Supply—Our Keystone, Conemaugh and Bridgeport stations operate on coal. Coal is delivered to our units through a combination of rail, truck, barge and ocean shipments.

In order to control emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. We currently have a coal supply contract from Indonesia under contract through 2017 for the Bridgeport facility and believe that additional coal would be available after 2017 as required.

- Gas Supply—Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipelines with which we have contracted. In addition, we have firm gas transportation contracted for this winter season to serve a portion of the gas requirements for our BEC station in New York.

We have 1.3 billion cubic feet-per-day of firm transportation capacity and 0.9 billion cubic feet-per-day of firm storage delivery under contract to meet our obligations under the BGSS contract. This volume includes capacity from the Pennsylvania and Ohio shale gas regions where we purchase the majority of our natural gas. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet.

Power has contracted for approximately 125 million cubic feet-per-day of delivery capability on the PennEast Pipeline from eastern Pennsylvania to New Jersey with a targeted in-service date in the latter half of 2018. This additional delivery capability will be used to supplement the BGSS contract.

- Oil—Oil is used as the primary fuel for one load following steam unit and four combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck or barge.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather, environmental regulations, and other factors. For additional information, see Item 7. MD&A—Executive Overview of 2016 and Future Outlook and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Markets and Market Pricing

The vast majority of Power’s generation assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of FERC:

- PJM Regional Transmission Organization—PJM conducts the largest centrally dispatched energy market in North America. It serves over 61 million people, nearly 19% of the total United States population, and has a record peak demand of 165,492 MW. The PJM Interconnection coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The majority of our generating stations operate in PJM.
- New York—The New York ISO (NYISO) is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 19 million and a record peak demand of 33,956 MW. Our BEC station operates in New York.
- New England—The ISO-New England (ISO-NE) is the market coordinator for the New England Power Pool and for administering its energy marketplace which covers Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 15 million and a record peak demand of 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials may increase or decrease our profitability.

Commodity prices, such as electricity, gas, coal, oil and environmental products, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. Over the long-term, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power; thereby placing us at greater risk should our generating units fail to operate effectively or otherwise become unavailable.

Over the past few years, lower wholesale natural gas prices have resulted in lower electric energy prices. One of the reasons for the lower natural gas prices is greater supply from more recently-developed sources, such as shale gas, much of which is

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produced in adjacent states (e.g. Pennsylvania). This trend has reduced margin on forward sales as we re-contract our expected generation output.

In addition to energy sales, we earn revenue from capacity payments for our generating assets. These payments are compensation for committing our generating units to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there will be sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system transfer limitations which raise concerns about reliability and create a more acute need for capacity.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater transparency regarding the value of capacity and provide a pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

The prices to be received by generating units in PJM for capacity have been set through RPM base residual and incremental auctions and depend upon the zone in which the generating unit is located. For each delivery year, the prices differ in the various areas of PJM, depending on the transfer limitations of the transmission system in each area. Keystone and Conemaugh receive lower capacity prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in New Jersey usually receive higher pricing.

Our PJM generating units are located in several zones and Power expects to realize the following average capacity prices from the base and incremental auctions which have been completed:

Delivery Year	MW-day
June 2016 to May 2017	$172
June 2017 to May 2018	$177
June 2018 to May 2019	$215
June 2019 to May 2020	$116

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

We have obtained price certainty for our PJM capacity through May 2020 and New England capacity through May 2021 through the RPM and FCM pricing mechanisms, respectively.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike the other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

On a prospective basis, many factors may affect the capacity pricing, including but not limited to:

- load and demand,
- availability of generating capacity (including retirements, additions, derates and forced outage rates),
- capacity imports from external regions,
- transmission capability between zones,
- available amounts of demand response resources,
- pricing mechanisms, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM and the other ISOs may propose over time, and
- legislative and/or regulatory actions that permit subsidized local electric power generation.

For additional information on the RPM and FCM markets, as well as on state subsidization through various mechanisms, see Regulatory Issues—Federal Regulation.

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Hedging Strategy

To mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS and similar full-requirements contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. The BGS-RSCP contract, a full-requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the BPU. The volume of BGS contracts and the mix of electric utilities that our generation operations serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

Load Zone ($/MWh)	2014-2017	2015-2018	2016-2019	2017-2020
PSE&G	$97.39	$99.54	$96.38	$90.78
Jersey Central Power & Light Company (JCP&L)	$84.44	$80.42	$74.85	$69.08
Atlantic City Electric Company	$87.80	$86.06	$82.14	$75.49
Rockland Electric Company	$95.61	$90.66	$85.02	$80.50

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in the effectiveness of our hedges. Actual output will vary based upon total market demand, the relative cost position of our units compared to other units in the market and the operational flexibility of our units. Hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey EDC, that is, the load that remains after some customers have chosen to be served directly either by third-party suppliers or through municipal aggregation. The amount of power supplied through the BGS auction varies based on the level of the EDC’s default load, which is affected by the number of customers who are served by third-party suppliers, as well as by other factors such as weather and the economy.

In recent years, as market prices declined from previous levels, there was an incentive for more of the smaller commercial and industrial electric customers to switch to third-party suppliers. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. As average BGS rates have declined to a level that more closely resembles current market prices, customers may see less of an incentive to switch to third-party suppliers. We are unable to determine the degree to which this switching, or “migration,” will continue, but the impact on our results could be material should market prices fall or rise significantly.

In 2016, Power announced its intention to develop a retail energy platform to sell physical electricity and natural gas directly to commercial and industrial customers. We believe a retail energy platform would complement our existing wholesale generation-to-load marketing business and is intended to hedge our generation at improved margins in the geographic areas where we have generation facilities. Power was granted licenses in 2016 to sell both electricity and gas in the states of New Jersey and Pennsylvania and expects to begin its marketing efforts in 2017.

As of February 9, 2017, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2019.

Base Load Generation	2017	2018	2019
Generation Sales	100%	80%-85%	35%-40%

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have

been the case had no hedging activity been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then-current market.
Our fuel strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2018 and a significant portion through 2021. We also have various long-term fuel purchase commitments for coal to support our Keystone, Conemaugh and Bridgeport Harbor stations. These purchase obligations are consistent with our strategy in general to enter into contracts for our fuel supply in comparable volumes to our sales contracts.

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We take a more opportunistic approach in hedging both the fuel for and the anticipated output of our natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units. Additionally, the recent development of low-cost gas supplies in the Marcellus region presents opportunities during certain portions of the year to procure gas for our generating units at attractive prices.

More than half of Power’s expected gross margin in the upcoming year relates to our hedging strategy, our expected revenues from the capacity market mechanisms described above and certain ancillary service payments such as reactive power.

Other

Energy Holdings primarily owns and manages a portfolio of domestic lease investments. The majority of Energy Holdings’ $649 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2016, the counterparties for 66% of our total leveraged lease investments were rated below investment grade by Standard & Poor’s (S&P). See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables for additional information.

Energy Holdings’ leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented on our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the United States (GAAP), the leveraged lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk, and Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

In accordance with a twelve year Amended and Restated Operations Services Agreement (OSA) entered into by PSEG LI and the LIPA, PSEG LI commenced operating LIPA’s electric T&D system in Long Island, New York on January 1, 2014. As required by the OSA, PSEG LI also provides certain administrative support functions to LIPA. PSEG LI uses its brand in the Long Island T&D service area. Pursuant to the OSA, PSEG LI acts as LIPA’s agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. In addition, there is the opportunity for the parties to extend the contract for an additional eight years subject to the achievement by PSEG LI of certain performance levels during the initial term of the OSA. Also, as of January 2015, Power began providing fuel procurement and power management services to LIPA under separate agreements.

COMPETITIVE ENVIRONMENT

PSE&G

Our transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. Increased reliance by customers on net-metered generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.

Changes in the current policies for building new transmission lines, such as those ordered by FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that previously provided us a "right of first refusal" (ROFR) to construct projects in our service territory, could result in third-party construction of transmission lines in our area in the future

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and also allow us to seek opportunities to build in other service territories. These implementing rules within the regions are still in flux so both the extent of the risk within our service territory and the opportunities for our transmission business elsewhere remain difficult to assess. For additional information, see the discussion in Regulatory Issues—Federal Regulation—Transmission Regulation, below.

Construction of new local generation and changing customer usage patterns also have the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.

Power

Various market participants compete with us and one another in buying and selling in the wholesale energy markets, entering into bilateral contracts and selling to aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers,
- banks, funds and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

New additions of lower-cost or more efficient generation capacity could make our plants less economic in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions would impact market prices and our competitiveness.

Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, weather, municipal aggregation and other customer migration and other factors. In addition, how resources such as demand response and capacity imports are permitted to bid into the capacity markets also affects the prices paid to generators such as Power in these markets. It is also possible that advances in technology, such as distributed generation and micro grids, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the electric transmission system relieve or reduce limitations and constraints in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing what types of transmission will be built, who is selected to build transmission and who will pay the costs of future transmission could also impact our generation revenues.

Adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, would have the effect of artificially depressing prices in the competitive wholesale market and thus have the potential to harm competitive markets, on both a short-term and a long-term basis. At the same time, changes implemented in the PJM and New England capacity markets and other proposed market changes discussed more fully in Regulatory Issues—Federal Regulation provide the opportunity for additional compensation in both the energy and capacity markets.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states.

While it is our expectation that efforts may be undertaken by the new administration, following the 2016 U.S. presidential election, to preserve the existing base of fossil generating plants, we still believe that pressures from renewable resources will continue to increase. For example, many parts of the country, including the mid-western region served by the Midwest Independent System Operator (MISO), the PJM region and the California ISO, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of “public policy” transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulation.

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EMPLOYEE RELATIONS

As of December 31, 2016, we had 13,065 employees within our subsidiaries, including 8,161 covered under collective bargaining agreements. Since the beginning of 2016, six of our eight labor unions ratified extensions of their collective bargaining agreements with us, with expiration dates from 2019 to 2021. The collective bargaining agreements for the remaining two unions expire in June 2017 and May 2018. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2016

	PSE&G	Power	PSEG LI	Other
Non-Union	1,898	1,165	811	1,030
Union	5,108	1,549	1,496	8
Total Employees	7,006	2,714	2,307	1,038

REGULATORY ISSUES

In the ordinary course of our business, we are subject to regulation by, and are party to various claims and regulatory proceedings with, FERC, the BPU, the Commodity Futures Trading Commission and various state and federal environmental regulators, among others. For information regarding material matters, other than those discussed below, see Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Federal Regulation

FERC

FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations. As a result of the change in administration following the U.S. presidential election, FERC does not currently have the quorum required to issue certain substantive orders. Until quorum is obtained, FERC Staff has been delegated authority, which allows FERC to continue carrying out its regulatory obligations in the absence of a quorum of Commissioners. The FERC order delegated to FERC Staff the ability to take certain actions to avoid filings going into effect by operation of law until FERC again has a quorum and moves to lift the delegation order.

FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain criteria established by FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

FERC also regulates Regional Transmission Operators (RTOs)/ISOs, such as PJM, and their energy and capacity markets.

For us, the major effects of FERC regulation fall into five general categories:

- Regulation of Wholesale Sales—Generation/Market Issues/Market Power
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

Regulation of Wholesale Sales—Generation/Market Issues/Market Power

Under FERC regulations, public utilities that wish to sell power at market rates must receive FERC authorization (“MBR Authority”) to sell power in interstate commerce before making power sales. They can sell power at cost-based rates or apply to FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR Authority, FERC must

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first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The following PSEG companies are public utilities and currently have MBR Authority: PSE&G, PSEG ER&T, PSEG Fossil, PSEG Nuclear, PSEG Power Connecticut, PSEG New Haven, PSEG Energy Solutions, Pavant Solar II LLC, San Isabel Solar LLC and Bison Solar LLC. FERC requires that holders of MBR Authority file an update every three years demonstrating that they continue to lack market power and/or that their market power has been sufficiently mitigated and report in the interim to FERC any material change in facts from those FERC relied on in granting MBR Authority.

In December 2016, the PSEG companies with MBR Authority filed their triennial market power analysis as required by FERC regulations. A FERC order on the PSEG companies' triennial filing is expected in the third quarter 2017.

Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. FERC rules also govern the overall design of these markets. At present, all units within a delivery zone receive a clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load) which can vary by location. In addition, recent rule changes in the energy markets administered by PJM and ISO-NE (see Capacity Market Issues below) impose rigorous performance obligations and nonperformance penalties on resources during times of system stress. These FERC rules have a direct impact on the prices received by our units.

FERC has also recently ordered certain favorable changes to energy market price formation rules improving shortage pricing and enhancing bidding flexibility for units. We continue to advocate in this context for additional changes in market rules that would provide more transparency about energy market prices. We cannot predict what action FERC might ultimately take, but such an examination could lead to future rule changes.

Capacity Market Issues

PJM, NYISO and ISO-NE each have capacity markets that have been approved by FERC. FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Issues presented in various forums include consideration of whether capacity market rules properly address and foster the development of state public policies, demand response (DR) and emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market outcomes. We cannot predict what action, if any, FERC might take with regard to capacity market design.

PJM—The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under the RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of the RPM in PJM continue to evolve and be refined in stakeholder proceedings and FERC proceedings in which we are active. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. However, aspects of FERC's order are currently pending appeal in the Court of Appeals for the D.C. Circuit (D.C. Circuit). 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. Efforts to modify the CP construct to enhance the participation of intermittent and DR resources ("seasonal resources") are currently pending before FERC. PJM has proposed modifications to the aggregation rules to improve the ability of seasonal resources to participate and two complaints have been filed requesting that FERC investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We expect either FERC action on PJM's proposal or inaction in the event that it goes into effect by operation of law before the upcoming base residual auction in May 2017. If PJM's proposal goes into effect by operation of law, there could be an increase in the participation of seasonal resources in the auction.

In September 2014, PJM filed at FERC to re-set the Variable Resource Requirement (VRR) curve for the RPM. PJM expects to reset the VRR every four years. Establishment of the VRR curve is a critical component in determining how generators are paid in the capacity auction. In November 2014, FERC accepted PJM's filing, which we believe represents an improvement over the status quo in terms of appropriately setting the demand curve. However, we and a trade association composed of other generators have challenged FERC's approval order on appeal at the D.C. Circuit, taking exception to FERC's approval of the manner in which PJM calculated the cost of capital and labor costs that form the basis for the Cost of New Entry component of the demand curve, which we believe have been set too low and do not accurately reflect the costs of building a new generating unit in PJM.

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Over the past several years, certain entities in PJM, namely, FirstEnergy Corp. (FE) and American Electric Power (AEP) sought financial support arrangements from the Ohio Public Utility Commission (PUCO) for certain coal plants and, for FE, a nuclear plant. FE and AEP originally proposed to enter into power purchase agreements (PPAs) with their non-utility generation affiliates providing for above-market purchases from these plants. The PUCO Staff proposed a payment to support modernization of the distribution system (distribution modernization rider) in the FE case which was ultimately accepted by the PUCO. The Dayton Power and Light Company also recently filed for a distribution modernization rider for the generating plants that it owns.

The PUCO proceedings created a concern that subsidized units within the PJM footprint would submit bids in the capacity market that are not reflective of their actual operating costs and would, in turn, artificially suppress capacity prices. As a result, certain parties requested that FERC should direct PJM to expand the “minimum offer price rule” to apply to existing units.

We are unable to predict the results of these pending proceedings or any future related proceedings or to calculate the potential impacts on our business.

MISO—MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. Significant quantities of capacity from MISO are imported into PJM which tends to have a downward effect on PJM capacity prices. However, recent enhancements to PJM market rules have tightened eligibility requirements for PJM imports and reduced these impacts. The issue of “capacity portability” from MISO continues to be examined in the stakeholder process.

ISO-NE—ISO-NE’s market for installed capacity in New England provides fixed capacity payments for generators, imports and DR. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. ISO-NE also employs a mechanism, similar to PJM’s CP mechanism, that provides incentives for performance and that imposes charges for non-performance during times of system stress. We view this mechanism as generally positive for generating resources as providing more robust income streams. However, it also imposes additional financial risk for non-performance. One aspect of the current market design that we do not support is the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. FERC has approved downward sloping demand curves and zonal curves for the three designated capacity zones for Forward Capacity Auction (FCA) 11. In addition, ISO-NE’s review of the Net Cost of New Entry (Net CONE) was recently submitted at FERC which would be implemented for FCA 12. If approved by FERC, the value of Net CONE will be reduced which could impact the revenues we expect to receive for our generation in the New England capacity market.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Various matters pending before FERC could affect the competitiveness of this market and the outcome of these proceedings could result in artificial price suppression unless sufficient market protections are adopted.

One capacity market matter pending before FERC involves rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons. In March 2015, FERC issued an order which held that units receiving special reliability payments could properly take those payments into account in formulating capacity market bids. We believe that this ruling could impact efficient price formation in the capacity market and could artificially suppress capacity market outcomes. In April 2015, a trade association, Independent Power Producers of New York, Inc. (IPPNY) of which Power is a member, filed for rehearing by FERC of this ruling. This rehearing is still pending. Also, in connection with this same proceeding, FERC required NYISO to submit a report addressing whether buyer-side mitigation measures are needed for new entry occurring in the “Rest of State” (ROS) region and for uneconomic retention and repowering anywhere in the state. NYISO filed a report with FERC in December 2015 contending that these measures are not needed. The IPPNY has opposed NYISO’s contentions. The matter remains pending before FERC. In addition, in May 2015, the New York Public Service Commission and other New York agencies filed a complaint at FERC requesting certain exemptions from the NYISO rules that prevent capacity suppliers from submitting bids that are not market competitive. On October 9, 2015, FERC granted in part, certain of the requested exemptions for renewable resources and for resources being used by the owner for self-supply. The IPPNY has challenged NYISO’s proposed implementation of the newly required exemptions. This challenge is still pending.

NYISO’s capacity market incorporates demand curves that are determined periodically by NYISO and approved by FERC. In November 2016, NYISO submitted to FERC for approval proposed demand curves that updated key parameters. The updated demand curves reflect the expected cost of new entry of peaking plants in New York and in each of the three capacity localities. If approved, this could impact the revenues we expect to receive for our generation in the New York capacity market. FERC issued an order substantially accepting NYISO’s proposed demand curves, but did not accept the proposal that the ROS proxy peaking unit design include selective catalytic reduction (SCR) emissions control technology.

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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. FERC recently issued a notice of proposed rulemaking (NOPR) proposing that RTOs/ISOs modify their rules governing fast-start resources. Fast-start resources typically are committed in real-time, very close to the interval when needed and can respond quickly to unforeseen system needs. However, without fast-start pricing, some fast-start resources are ineligible to set prices due to inflexible operating limits. As a result, prices may not reflect the marginal cost of serving load. In a separate proceeding, PJM has submitted a proposal at FERC's request to modify its rules to allow market sellers to submit day-ahead offers that vary by hour and to allow market sellers to update their offers in real time on an hourly basis under certain circumstances. These rule changes are currently pending before FERC. If both changes are approved, we believe that they would improve price formation in the energy and ancillary services markets.
Transmission Regulation
FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments.
In October 2016, PSE&G filed its 2017 Annual Formula Rate Update with FERC which requests approximately $121 million in increased annual transmission revenues effective January 1, 2017, subject to true-up. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. For additional information about our transmission formula rate, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.
Transmission Policy Developments—FERC concluded in Order 1000 that the incumbent transmission owner should not always have a ROFR to construct and own transmission projects in its service territory. We and other companies appealed Order 1000 but this appeal was denied in 2014 by the D.C. Court. The current PJM rules retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents' use of their rights-of-way.
In a September 2015 order, FERC directed that a technical conference be held to address "concerns regarding how PJM plans for local transmission projects." Parties in the case raised concerns that too many projects are being approved outside of the Regional Transmission Expansion Plan (RTEP) mechanism to address "local" reliability requirements without going through the Order 1000 open window process. Intervenors also complained that there is inadequate transparency regarding the PJM transmission owners' consideration and selection of Supplemental Projects (which are not approved by the PJM Board). PSE&G is participating in the process before FERC in support of the current PJM processes. In addition, certain PJM stakeholders have proposed an examination of the current planning rules, including changes with regard to criteria to be used for replacement of facilities that have reached their "end of life." PSE&G has been actively participating in this process. However, we are unable to predict the outcome of these efforts.
In a February 2016 order, FERC reversed a previous order and accepted a filing by the PJM transmission owners seeking authority to assign costs for RTEP projects (subject to PJM Board approval requirements) solely addressing localized needs to customers within the local transmission owner's zone. FERC's action in this order provides an exemption from the Order 1000 open window procedures for projects constructed by transmission owners to meet local transmission planning criteria. In April 2016, PJM filed at FERC to incorporate a voltage threshold into PJM's RTEP process to exempt, except under certain circumstances, reliability violations on facilities below 200 kV from PJM's proposal window process. We generally support this reform as a measure to improve the efficiency of the open

window procedure that will permit transmission developers to focus on the projects most likely to benefit from a competitive process.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G contending that insufficient levels of costs are being allocated to customers in the PSE&G transmission zone. Projects involved include the Artificial Island project, the Bergen-Linden project in New Jersey and a smaller project in Sewaren, New Jersey. In April 2016, FERC issued orders denying the complaints and leaving the current cost allocation in effect as to the Artificial Island and Bergen-Linden projects. Due to an intervening FERC order concerning the allocation of costs for projects constructed to meet local reliability requirements, FERC directed that all of the Sewaren costs be allocated to customers in the PSE&G transmission zone. It is anticipated that additional proceedings are likely to occur.

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In February 2016, FERC issued an order granting PSE&G's request that it be permitted to seek recovery of 100% of its portion of the project's costs to address identified high voltage issues at Artificial Island in New Jersey if the project is canceled for reasons beyond PSE&G's control. In April 2016, PSE&G accepted construction responsibility for the three components of the project that PJM assigned to it, based on having reached agreement with PJM regarding an estimate for the project base cost of $273 million, plus risk and contingency for a total project cost of up to $340 million. In August 2016, PJM announced that it had suspended the Artificial Island transmission project and would be performing a comprehensive analysis to support a future course of action. PJM is expected to submit its final recommendation to the PJM Board at the April 2017 Board meeting.

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. FERC set the complaint for hearing and settlement procedures and the parties are currently engaged in discovery. We are unable to predict the outcome of these proceedings.

Another proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kV projects in PJM that either have been built or are in the process of being built, including the Susquehanna-Roseland project. A proposed settlement was filed with FERC in June 2016. The settlement, if adopted by FERC, would result in increased annual cost allocations to customers in the PSE&G transmission zone. Under this settlement, Power, as a BGS supplier could become obligated to pay amounts previously paid by other PJM transmission customers. However, we do not believe that the anticipated level of any such potential payments would have a material effect on Power's financial statements. We believe that there is a mechanism in place under the BGS contract for the pass-through of increases in transmission charges.

Transmission Rate Proceedings—Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base ROEs. Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G's transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Con Edison Wheeling Agreement—In April 2016, Con Edison informed PJM that it would allow its Wheeling Agreement to expire effective as of May 1, 2017. The Wheeling Agreement enables Con Edison to move 1,000 MW of power from southeastern New York across the PSE&G system for delivery into New York City. NYISO and PJM submitted proposed tariff provisions in January 2017. The proposal concerns future operational procedures and transmission planning assumptions associated with the affected transmission lines. The manner in which PJM has calculated the import assumptions for the upcoming base residual auction has decreased the potential for locational splits in the zones where PSEG has its assets. However, PJM has indicated that it is still reviewing these import assumptions and may publish revised values before the auction. We cannot predict the impact of the proposal on energy prices or transmission planning at this time. Also, PSE&G will continue to recover the costs associated with the new arrangement through its formula rate. However, we continue to review the proposal and may protest certain of its elements.

Compliance

FERC—For information about the preliminary non-public investigation initiated by the FERC Staff regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Reliability Standards—Congress has required FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the U.S. electric transmission and generation system (grid) and to prevent major system blackouts. There has been considerable focus recently on physical security in light of, among other things, a substation attack in California that occurred in 2013. As a result, FERC directed the NERC to draft a physical security standard intended to further protect assets deemed “critical” to reliability of the grid. In November 2014, FERC issued an order approving the NERC’s proposed physical security standard. Under the standard, utilities will be required to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. In our case, the third-party is PJM. As part of these plans, utilities could decide or be required to build additional redundancy into their systems. This standard will supplement the Critical Infrastructure Protection standards that are already in place and that establish physical and cybersecurity protections for critical systems. We are taking steps to meet the new obligations. FERC directed the NERC to develop a new reliability standard to provide security controls for supply chain management associated with the procurement of industrial control system hardware, software, and services related to bulk electric system operations. When adopted, compliance with these new standards would be expected to impose additional obligations and costs.

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Commodity Futures Trading Commission (CFTC)

In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), the SEC and the CFTC are in the process of implementing a new regulatory framework for swaps and security-based swaps. The legislation was enacted to reduce systemic risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. To implement the Dodd-Frank Act, the CFTC has engaged in a comprehensive rulemaking process and has issued a number of proposed and final rules addressing many of the key issues. We are currently subject to recordkeeping and data reporting requirements applicable to commercial end users. The CFTC has also re-proposed rules establishing position limits for trading in certain commodities, such as natural gas, and we will begin complying with these rules once they become final.

Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. The current operating licenses of our nuclear facilities expire in the years shown in the following table:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in 2011, the NRC began performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan have resulted in additional regulation and implementation guidance for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.

We have implemented the diverse and flexible mitigating strategies and spent fuel pool level indication modifications in accordance with the regulatory requirements at the Salem, Hope Creek and Peach Bottom nuclear units. For our Hope Creek and Peach Bottom units, implementation of the required venting system modifications is expected to be completed by 2018.

The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident.

We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states' regulations due to our operations in those states.

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate case was settled in 2010. As a result of our 2014 Energy Strong Order, we are required to file our next distribution base rate case proceeding no later than November 1, 2017. In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the

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recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Gas System Modernization Program (GSMP)—In November 2015, the BPU issued an order approving the settlement of our GSMP through which PSE&G will invest $905 million over the next three years to modernize its gas system. The settlement enables 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 $650 million of the investment through an accelerated recovery mechanism. Under the settlement, PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case. In December 2016, the BPU approved PSE&G's initial GSMP cost recovery petition which allows PSE&G to recover in base rates capitalized GSMP investment costs for infrastructure placed in service through September 30, 2016. The BPU order provides for a total $10 million annual revenue increase effective January 1, 2017.

BPU Cybersecurity Requirements for Regulated Entities—In March 2016, the BPU issued an order for the regulated electric, natural gas, and water/wastewater utilities to further reduce the potential for cyber threats to the reliability and resiliency of utility service and to protect customers' information. The order requires these regulated utilities, including PSE&G, to, among other conditions, implement a cybersecurity program that defines and implements organization accountabilities and responsibilities for cyber risk management activities, and establishes policies, plans, processes and procedures for identifying and mitigating cyber risk to critical systems.

In December 2016, PSE&G submitted a required letter to the BPU outlining its compliance efforts to date and noting that it currently has not identified any potential barriers to compliance with the order's requirements. New Jersey utilities, including PSE&G, are required to be compliant with these requirements by October 1, 2017, taking various measures aimed to meet this compliance deadline. For a discussion of the risks associated with cyber threats, see Item 1A. Risk Factors.

Solar 4 All Program Extension II—In November 2016, the BPU approved a settlement providing for an extension of PSE&G's existing landfill/brownfield solar program to construct up to 33 MW of grid connected facilities with projected capital expenditures of approximately $80 million through May 2020.

Consolidated Tax Adjustments (CTA)—New Jersey is one of only a few states that make CTA in setting rates for regulated utilities. These adjustments to rate base are made during the rate setting process and are intended to allocate to utility customers a portion of the tax benefits realized from the filing of a consolidated federal tax return by the utility's parent corporation. The BPU has been considering the appropriateness of the adjustment and the methodology and mechanics of the calculation for some time. In October 2014, the BPU approved a proposal by its Staff that limits the tax benefit period to be considered in the calculation to five years, sets the rate base adjustment at 25% of any such tax benefit and eliminates from the process any tax benefits tied to transmission earnings. In accordance with this October action, this CTA policy will be applied only with respect to future rate cases. The adoption of these modifications by the BPU is not expected to have a material impact on PSE&G's current earnings nor in its next rate case filing. In November 2014, the New Jersey Division of Rate Counsel appealed the BPU's decision which remains pending.

Connecticut Rate Filing—In June 2016, Power's subsidiary, PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority for recovery of its costs and investment in its Connecticut-based peaking unit. Power requested 2017 revenues of $20 million, which was approved in its entirety.

Additional matters are discussed in Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

ENVIRONMENTAL MATTERS

We are subject to federal, state and local laws and regulations with regard to environmental matters including, but not limited to:

- air pollution control,
- climate change,
- water pollution control,
- hazardous substance liability, and
- fuel and waste disposal.

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We expect there will be changes to existing environmental laws and regulations, particularly in light of the change in administration following the 2016 U.S. presidential election, which could significantly impact the manner in which our operations are currently conducted. Such laws and regulations may also affect the timing, cost, location, design, construction and operation of new facilities. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A—Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material.

For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes recordkeeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws. The CAA requires all major sources, such as our generation facilities, to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in our estimates of capital expenditures.

Hazardous Air Pollutants Regulation—In February 2012, the Environmental Protection Agency (EPA) published Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources under the National Emission Standard for Hazardous Air Pollutants (NESHAP) provisions of the CAA. The MATS established allowable levels for mercury as well as other hazardous air pollutants and went into effect in April 2015. In June 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants. In April 2016, the EPA released the final Supplemental Finding that considers the materiality of costs in determining whether to regulate hazardous air pollutants from power plants in response to the U.S. Supreme Court's ruling. Industry participants and various state authorities have filed petitions with the D.C. Court challenging the EPA's Supplemental Finding. We do not expect this Supplemental Finding to impact operation of our facilities.

Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation—In March 2013, Power filed a petition at the EPA challenging the NESHAP for RICE issued in January 2013. Among other things, the NESHAP include 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). In its petition, 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. In September 2015, the D.C. Court granted the EPA's motion for voluntary remand of the 50 hour exemption provision to the EPA. In May 2016, the D.C. Court vacated the 100 hour exemption which removes that provision from the rule.

Cross-State Air Pollution Rule (CSAPR)—In January 2015, the final CSAPR became effective which limits power plant emissions of sulfur dioxide (SO_2) and annual and ozone season nitrogen oxide (NO_x) in 28 states that contribute to the ability of downwind states to attain and/or maintain the 1997 and 2006 particulate matter and the 1997 ozone National Ambient Air Quality Standards (NAAQS). In April 2015, the EPA revoked the 1997 ozone NAAQS of 80 parts per billion (ppb) and began implementation of the more stringent 2008 ozone NAAQS of 75 ppb. In September 2016, the EPA published the final CSAPR Updating Rule to address the 2008 National Ambient Air Quality Standards for ground-level ozone. The rule establishes more stringent annual ozone season (May 1 through September 30) caps beginning in May 2017. We do not anticipate any material impact on our business or financial condition due to the

CSAPR. Numerous parties have filed petitions for review with the D.C. Court to challenge the CSAPR Updating Rule.

Ozone Standard—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 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. Numerous parties have filed petitions for review with the D.C. Court to challenge the rule.

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Climate Change

CO_2 Regulation under the CAA—In October 2015, the EPA published the New Source Performance Standards (NSPS) for new power plants. The NSPS establishes two emission standards for CO_2 for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units, and (ii) natural gas combustion turbines. Simple cycle combustion turbines are exempt from the rule.

In October 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.

Numerous states, including New Jersey, and several industry groups filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners sought a stay of the rule. The U.S. Supreme Court stayed the rule pending further review of the case.

The U.S. Supreme Court's decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

Regional Greenhouse Gas Initiative (RGGI)—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. New Jersey withdrew from RGGI in 2012. However, certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions.

These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or through secondary markets.

In November 2015 the RGGI States initiated a 2016 Program Review stakeholder process. The focus of the 2016 Program Review is the post-2020 caps on GHG emissions and the incorporation of the EPA's CPP requirements.

New Jersey adopted the Global Warming Response Act in 2007, which calls for stabilizing its GHG emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the NJDEP, the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program through state action. We also have ownership interests in facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern our facilities in those jurisdictions.

Steam Electric Effluent Guidelines—In September 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 Bridgeport Harbor stations and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. We are unable to predict if this rule will have a material impact on our future capital requirements, financial condition and results of operations.

In addition to regulating the discharge of pollutants, the FWPCA regulates the intake of surface waters for cooling. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the FWPCA requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling and do not use cooling towers to recycle water for cooling purposes.

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The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant.

Cooling Water Intake Structure Regulation—In May 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act (CWA) that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

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

In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act. The cases were subsequently consolidated at the Second Circuit and a decision is expected by mid-2017.

We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities for additional information.

In June 2016, the New Jersey Department of Environmental Protection (NJDEP) issued the final New Jersey Pollutant Discharge Elimination System (NJPDES) permit for Salem, with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the Clean Water Act, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP’s issuance of a final NJPDES renewal permit for Salem. The Riverkeeper’s filing does not change the effective date of the permit. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

We are actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA’s CWA Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, we would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire the BH3 within five years of the effective date of the final permit. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in 2017 with a retirement date for BH3 by summer 2021, which is four years earlier than the previously estimated useful life ending in 2025. If the permit is not issued and the conditions below are not met, we may seek to operate BH3 through the previously estimated useful life.

Separately, we have also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that we would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates, which could occur in 2017. Absent those conditions being met, and the permit renewal referred to above not being issued, we may seek to operate BH3 through the previously estimated useful life. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements.

In February 2016, the proposed generating facility, Bridgeport Harbor Station Unit 5 (BH5), was awarded a capacity obligation. Construction is expected to commence in 2017, with operations expected to begin in mid-2019. The Connecticut Siting Council issued an order to approve siting BH5. All major environmental permits have been obtained except for the New Source air permit that is currently in draft form for public comment.

Waters of the United States—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 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 in June 2015 and various states, industry coalitions and environmental organizations have initiated legal action related to the provisions of the final rule as well as which court has jurisdiction over the rule. The U.S. Supreme Court is expected to rule on the question of jurisdiction by June 2017. 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.

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Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance—In April 2015, we determined that monitoring and reporting practices related to certain permitted wastewater discharges at our Bridgeport Harbor station may have violated conditions of the station’s NPDES permit and applicable regulations and could subject us to fines and penalties. We have notified the CTDEEP of the issues and have taken actions to investigate and resolve the potential non-compliance. We cannot predict the impact of this matter.

Endangered Species Act—In June 2015, the Sierra Club and another environmental group submitted to the NJDEP a sixty-day notice of intent to sue alleging the agency has caused violations of the Endangered Species Act by allowing our Mercer generation station to operate in a manner which has caused the mortality of certain species of sturgeon. Among other things, the notice requested the NJDEP to prioritize completion of a permit renewal action for Mercer which addresses the alleged Endangered Species Act violations. We are currently working with the National Marine Fisheries Service regarding an Incidental Take Permit that will outline operation and monitoring requirements through retirement of the Mercer generation station in May 2017 and subsequent decommissioning.

Hazardous Substance Liability

The production and delivery of electricity and the distribution and manufacture of gas result in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. See Item 3. Legal Proceedings. Our historic operations 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. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We no longer manufacture gas. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Site Remediation—The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.

Natural Resource Damages—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change, although such impacts could be material.

Fuel and Waste Disposal

Nuclear Fuel Disposal—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the DOE conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In June 2012, the court ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee. Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. Since May 2014, the DOE reduced the nuclear waste fee to zero. Prior to the elimination of this fee, the annualized pre-tax cost was approximately $30 million.

We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.

Low Level Radioactive Waste—As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level

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radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, there are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.

Coal Combustion Residuals (CCRs)—In December 2014, the EPA issued a final rule that 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. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for additional information.

In December 2016, the Water Infrastructure Improvements for the Nation Act was enacted, which includes provisions regarding CCRs which allow for implementation of the EPA CCR rule through a state or EPA-based permit program. We believe this will have minimal impact to our operations.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Item 8. Financial Statements and Supplementary Data—Note 23. Financial Information by Business Segment.

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EXECUTIVE OFFICERS OF THE REGISTRANT (PSEG)

Name	Age as of December 31, 2016	Office	Effective Date First Elected to Present Position
Ralph Izzo	59	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Services)	January 2010 to present
Daniel J. Cregg	53	Executive Vice President and CFO (PSEG)	October 2015 to present
		Executive Vice President and CFO (PSE&G)	October 2015 to present
		Executive Vice President and CFO (Power)	October 2015 to present
		Vice President-Finance (PSE&G)	June 2013 to October 2015
		Vice President-Finance (Power)	December 2011 to June 2013
William Levis	60	President and Chief Operating Officer (Power)	June 2007 to present
Ralph LaRossa	53	President and Chief Operating Officer (PSE&G)	October 2006 to present
		Chairman of the Board of PSEG Long Island LLC	October 2013 to present
Derek M. DiRisio	52	President (Services)	August 2014 to present
		Vice President and Controller (PSEG)	January 2007 to August 2014
		Vice President and Controller (PSE&G)	January 2007 to August 2014
		Vice President and Controller (Power)	January 2007 to August 2014
		Vice President and Controller (Energy Holdings)	January 2007 to August 2014
		Vice President and Controller (Services)	January 2007 to August 2014
Tamara L. Linde	52	Executive Vice President and General Counsel (PSEG)	July 2014 to present
		Executive Vice President and General Counsel (PSE&G)	July 2014 to present
		Executive Vice President and General Counsel (Power)	July 2014 to present
		Vice President - Regulatory (Services)	December 2006 to July 2014

Stuart J. Black	54	Vice President and Controller (PSEG)	August 2014 to present
		Vice President and Controller (PSE&G)	August 2014 to present
		Vice President and Controller (Power)	August 2014 to present
		Vice President (Services) and Assistant Controller (Power)	March 2010 to August 2014

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ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our business, prospects, financial position, results of operations or cash flows and could cause results to differ materially from those expressed elsewhere in this report.

MARKET AND COMPETITION RISKS

Fluctuations in the wholesale power and natural gas markets could negatively affect our financial condition, results of operations and cash flows.

In the markets where we operate, natural gas prices have a major impact on the price that generators receive for their output. Over the past several years, wholesale prices for natural gas have remained well below the peak levels experienced in 2008, in part due to increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly.

In October 2016, Power determined that it will cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. The primary factors considered during this process that contributed to the decision to retire these units early include significant declines in revenues and margin caused by the sustained period of depressed wholesale power prices and reduced capacity factors caused by lower natural gas prices making coal generation less economically competitive than natural gas-fired generation. Despite experiencing recent warmer than normal weather in PJM this summer, Power did not experience the usual increase in electricity prices in PJM as it had in past hot summers. This trend has a further adverse economic impact to these units because they generally dispatch and earn energy margin on peak hot and cold days. In addition, the upcoming PJM capacity auction in May 2017 for the capacity period from June 2020 to May 2021 will be the first to require all generating units to meet the increased operating performance standards of PJM's new capacity performance regulations. During the current annual five-year strategic planning process, Power determined, on October 3, 2016, that the costs to upgrade the existing units at the Hudson and Mercer stations to comply with these higher reliability standards to be too significant and not economic given current market conditions, including anticipated future capacity prices, current forward energy prices and past operational performance results of the units. The decision to retire the Hudson and Mercer units early had and will continue to have a material effect on PSEG's and Power's results of operations through the retirement date.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to ensure their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact our ability to operate or maintain these assets in the future. These generating stations may be impacted by factors such as continued depressed wholesale power prices or capacity factors, among other things. Any early retirement of these coal units before the end of their current estimated useful lives or change in the classification as held for use may have a material adverse impact on PSEG's and Power's future financial results.

Low natural gas prices, as well as continuing costs for regulatory compliance and federal and state-level policies that provide credits to renewable energy such as wind and solar, but do not apply to nuclear generating stations, have been a contributing factor to the significantly reduced revenues from nuclear generating stations while simultaneously raising the unit cost of production. If these trends continue or worsen, our nuclear generating units could cease being economically competitive which may cause us to retire such units prior to the end of their useful lives. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs and environmental remediation costs, could be material.

We may be unable to obtain an adequate fuel supply in the future.

We obtain substantially all of our physical natural gas, coal and nuclear fuel supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our fuel supply arrangements must be coordinated with transportation agreements, balancing agreements, storage services, financial hedging transactions and other contracts to ensure that the natural gas, coal and nuclear fuel is delivered to our power plants at the times, in the quantities and otherwise in a manner that meets the needs of our generation portfolio and our customers. We must also comply with laws and regulations governing the transportation of such fuels.

Additionally, the PJM power market has recently experienced an increase in natural gas-fired generation assets that supply electricity to the region. As a result, there has been a corresponding increase in the need for natural gas transportation assets to serve power generation assets. When extreme cold temperatures rapidly increase the demand for natural gas used for residential heating, it can also create constraints on natural gas pipelines that serve power generation assets. When these conditions exist, it could interrupt the fuel supply to our natural gas-fired power plants in the PJM power market.

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We are exposed to increases in the price of natural gas, coal and nuclear fuel, and it is possible that sufficient supplies to operate our generating facilities profitably may not continue to be available to us. Significant changes in the price of natural gas and nuclear fuel could affect our future results and impact our liquidity needs. In addition, we face risks with regard to the delivery to, and the use of natural gas, coal and nuclear fuel by, our power plants including the following:

- transportation may be unavailable if pipeline infrastructure is damaged or disabled;
- pipeline tariff changes may adversely affect our ability to, or cost to, deliver such fuels;
- creditworthiness of third-party suppliers, defaults by third-party suppliers on supply obligations and our ability to replace supplies currently under contract may delay or prevent timely delivery;
- market liquidity for physical supplies of such fuels or availability of related services (e.g. storage) may be insufficient or available only at prices that are not acceptable to us;
- variation in the quality of such fuels may adversely affect our power plant operations;
- legislative or regulatory actions or requirements, including those related to integrity inspections, may increase the cost of such fuels;
- fuel supplies diverted to residential heating may limit the availability of such fuels for our power plants; and
- the loss of critical infrastructure, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences could impede the delivery of such fuels.

Our nuclear facilities and certain of our other generation facilities require fuel that may only be available from one or a limited number of suppliers. The availability and price of this fuel may vary due to supplier financial or operational disruptions, transportation disruptions and force majeure. At times, such fuel may not be available at any price, or we may not be able to transport it to our facilities on a timely basis. In this case, we may not be able to run those facilities even if it would be profitable. If we had sold forward the power from such a facility, we could be required to supply or purchase power from alternate sources, perhaps at a loss. This could have a material adverse impact on the financial results of specific plants and on our results of operations.

Our nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire nuclear fuel in the future. Although our fuel contract portfolio provides a degree of hedging against these market risks, such hedging may not be effective and future increases in our fuel costs could materially and adversely affect our liquidity, financial condition and results of operations. While our generation runs on a mix of fuels, primarily natural gas and nuclear fuel, an increase in the cost of any particular fuel ultimately used could impact our results of operations.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues provided by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements or other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served. Changes in prevailing market prices could have a material adverse effect on our financial condition and results of operations. Factors that may cause market price fluctuations include:

- increases and decreases in generation capacity, including the addition of new supplies of power as a result of the development of new power plants, expansion of existing power plants or additional transmission capacity;
- power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including power plant outages and transmission disruptions;
- weather conditions, particularly unusually mild summers or warm winters in our market areas;
- quarterly and seasonal fluctuations;
- economic and political conditions that could negatively impact demand for power;
- changes in the supply of, and demand for, energy commodities;

- development of new fuels or new technologies for the production or storage of power;
- federal and state regulations and actions of the ISOs; and

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- federal and state power, market and environmental regulation and legislation, including financial incentives for new renewable energy generation capacity that could lead to oversupply.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur material losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These risks cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices.

We face significant competition in the wholesale energy and capacity markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our business objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy and capacity markets, potentially resulting in erosion of our market share and impairment in the value of our power plants. Recently, certain states have taken, or are considering taking, actions to subsidize or otherwise provide economic support to renewables, energy efficiency initiatives and existing, uneconomic generation facilities that could adversely affect capacity and energy prices. Increased generation supply and lower energy prices due to these subsidies could have an adverse impact on our results of operations.

The introduction or expansion of technologies related to energy generation, distribution and consumption and changes in customer usage patterns and could adversely impact us.

The power generation business has seen a substantial change in the technologies used to produce power. Newer generation facilities are often more efficient than aging facilities, which may put some of these older facilities at a competitive disadvantage to the extent newer facilities are able to consume the same or less fuel to achieve a higher level of generation output. Federal and state incentives for the development and production of renewable sources of power has allowed for the penetration of competing technologies, such as wind, solar, and commercial-sized power storage. Additionally, the development of DSM tools and practices can impact peak demand requirements for some of our markets at certain times during the year. The continued development of subsidized, competing power generation technologies and significant development of DSM tools and practices could alter the market and price structure for power generation and could result in a reduction in load requirements, negatively impacting our financial condition, results of operations and cash flows. Additionally, technological advances driven by federal laws mandating new levels of energy efficiency in end-use electric devices or other improvements in, or applications of, technology could lead to declines in per capita energy consumption.

Advances in distributed generation technologies, such as fuel cells, micro turbines, micro grids, windmills and net-metered solar installations, may reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. Large customers, such as universities and hospitals, continue to explore potential micro grid installation. Such developments could (i) affect the price of energy, (ii) reduce energy deliveries as customer-owned generation becomes more cost-effective, (iii) require further improvements to our distribution systems to address changing load demands and (iv) make portions of our transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy.

Some or all of these factors, could result in a lack of growth or decline in customer demand for electricity or number of customers, and may cause us to fail to fully realize anticipated benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows. These factors could also materially affect our results of operations, cash flows or financial positions through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Economic downturns would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices for power, generation capacity and natural gas, which can fluctuate substantially. Increased unemployment of residential customers and decreased demand for products and services provided by commercial and industrial customers resulting from an economic downturn could lead to declines in the demand for energy and an increase in the number of uncollectible customer balances, which would negatively impact our overall sales and cash flows. Although our utility

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business is subject to regulated allowable rates of return, overall declines in electricity and gas sold could materially adversely affect our financial condition, results of operations and cash flows. Additionally, prolonged economic downturns that negatively impact our financial condition, results of operations and cash flows could result in future material impairment charges to write down the carrying value of certain assets to their respective fair values.

We are subject to third-party credit risk relating to our sale of generation output and purchase of fuel.

We sell generation output and buy fuel through the execution of bilateral contracts. We also seek to contract in advance for a significant proportion of our anticipated output capacity and fuel needs. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could require Power to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, which could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of the default sharing mechanisms that exist in those markets, some of which attempt to spread the risk across all participants. Therefore, a default by a third party could increase our costs, which could negatively impact our results of operations and cash flows.

Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Market performance and other factors could decrease the value of trust assets and could result in the need for significant additional funding.

The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our defined benefit plans and to decommission our nuclear generating plants. A decline in the market value of our nuclear decommissioning trust funds could increase Power's funding requirements to decommission its nuclear plants. A decline in the market value of the defined benefit plan trust funds could increase our pension and other postretirement benefit (OPEB) plan funding requirements. The market value of our trusts could be negatively impacted by decreases in the rate of return on trust assets, decreased interest rates used to measure the required minimum funding levels and future government regulation. Additional funding requirements for our defined benefit plans could be caused by changes in required or voluntary contributions, an increase in the number of employees becoming eligible to retire and changes in life expectancy assumptions. Increased costs could also lead to additional funding requirements for our decommissioning trust. Failure to adequately manage our investments in our nuclear decommissioning trust and defined benefit plan trusts could result in the need for us to make significant cash contributions in the future to maintain our funding at sufficient levels, which would negatively impact our results of operations, cash flows and financial position.

REGULATORY, LEGISLATIVE AND LEGAL RISKS

PSE&G's revenues, earnings and results of operations are dependent upon state laws and regulations that affect distribution and related activities.

PSE&G is subject to regulation by the BPU. Such regulation affects almost every aspect of its businesses, including its retail rates, and failure to comply with these regulations could have a material adverse impact on PSE&G's ability to operate its business and could result in fines, penalties or sanctions. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. As a result of our Energy Strong Order, we are required to file our next distribution base rate case proceeding no later than November 1, 2017. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of costs and earn returns on authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU and are subject to prudency reviews. Inability to obtain fair or timely recovery of all our costs, including a return of, or on, our investments in rates, could have a material adverse impact on our results of operations and cash flows. In addition, if legislative and regulatory structures were to evolve in such a way that PSE&G's exclusive rights to serve its regulated customers were eroded, its future earnings could be negatively impacted.

Efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as rooftop solar and battery storage, in PSE&G's service territories could result in customers leaving the electric distribution system and an increase in customer net energy metering. Over time, customer adoption of these and other technologies and increased energy efficiency could adversely impact PSE&G's revenue and ability to fully recover the costs, which could require PSE&G to pursue a rate case to adjust revenue requirements or seek recovery though other mechanisms.

The BPU also conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. A finding by the BPU of non-compliance with these requirements could result in fines, a reduction in PSE&G's authorized base rate or the disallowance of the recovery of certain costs, which could have a materially adverse impact on our business, results of operations and cash flows.

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In addition, PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. Government officials, legislators and advocacy groups are aware of the affiliation between PSE&G and Power. In periods of rising utility rates, those officials and advocacy groups may question or challenge costs and transactions incurred by PSE&G with Power, irrespective of any previous regulatory processes or approvals underlying those transactions. The occurrence of such challenges may subject Power to a level of scrutiny not faced by other unaffiliated competitors in those markets and could adversely affect retail rates received by PSE&G in an effort to offset any perceived benefit to Power from the affiliation.

PSE&G periodically files base rate case proceedings. Such proceedings are at times contentious, lengthy and subject to appeal, which could lead to uncertainty as to the ultimate results and which could introduce time delays in effectuating rate changes.

PSE&G periodically files base rate case proceedings with the BPU. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for PSE&G to recover its costs by the time the rates become effective. Established rates are also subject to subsequent reviews by state regulators, whereby various portions of rates could be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, MGP remediation, smart grid infrastructure and energy efficiency, demand response and renewable energy programs. If the base rate case proceeding is protracted or results in approved rates that do not allow PSE&G to fully recover its costs or result in ROEs that are below historical levels, our financial condition, results of operations and cash flows would be materially adversely impacted. Our next distribution base rate case proceeding is required to be filed no later than November 1, 2017.

We are subject to comprehensive federal regulation that affects, or may affect, our businesses.

We are subject to regulation by federal authorities. Such regulation affects almost every aspect of our businesses, including management and operations; the terms and rates of transmission services; investment strategies; the financing of our operations and the payment of dividends. Failure to comply with these regulations could have a material adverse impact on our ability to operate our business and could result in fines, penalties or sanctions.

Recovery of wholesale transmission rates—PSE&G’s wholesale transmission rates are regulated by FERC and are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. In addition, transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates. These agencies and groups have filed complaints with FERC asking to reduce the base ROE of various transmission owners. They point to changes in the capital markets as justification for lowering the ROE of these companies. While we are not the subject of any of these complaints, they could set a precedent for FERC-regulated transmission owners, such as PSE&G. Inability to obtain fair or timely recovery of all our costs, including a return of or on our investments in rates, could have a material adverse impact on our business.

NERC Compliance—Mandatory NERC and Critical Infrastructure Protection standards have been established to ensure the reliability of the U.S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by NERC for compliance and are subject to penalties for non-compliance with applicable NERC standards. Failure to comply with such standards could result in penalties or increased costs to bring such facilities into compliance. Such penalties and costs, as well as lost revenue from prolonged outages required to bring facilities into compliance with these standards, could materially adversely impact our business, results of operations and cash flows.

Market-Based Rate (MBR) Authority and Other Regulatory Approvals—Under FERC regulations, public utilities that wish to sell power at market rates must receive MBR Authority before making power sales, and the majority of our businesses operate with such authority. Failure to maintain MBR authorization, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on our business, financial condition and results of operations.

In December 2016, the PSEG companies with MBR Authority filed their triennial market power analysis as required by FERC regulations. A FERC order on the PSEG companies' triennial filing is expected in the third quarter 2017.

Oversight by the Commodity Futures Trading Commission (CFTC) relating to derivative transactions—The CFTC has regulatory oversight of the swap and futures markets, including energy trading, and licensed futures professionals such as brokers, clearing members and large traders. Changes to regulations or adoption of additional regulations by the CFTC, including any regulations relating to position limits on futures and other derivatives or margin for derivatives and increased investigations by the CFTC, could negatively impact Power's ability to hedge its portfolio in an efficient, cost-effective manner by, among other things, potentially decreasing liquidity in the forward commodity and derivatives markets or limiting Power's ability to utilize non-cash collateral for derivatives transactions.

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We may also be required to obtain various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

Approximately half of our total generation output each year is provided by our nuclear fleet. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

Storage and Disposal of Spent Nuclear Fuel—Federal law requires the DOE to provide for the permanent storage of spent nuclear fuel but the DOE has not yet begun accepting spent nuclear fuel. Until a federal site is available, we use on-site storage for spent nuclear fuel, which is reimbursed by the DOE. However, future capital expenditures may be required to increase spent fuel storage capacity at our nuclear facilities. Once a federal site is available, the DOE may impose fees to support a permanent repository. In addition, the on-site storage for spent nuclear fuel may significantly increase the decommissioning costs of our nuclear units.

Regulatory and Legal Risk—We may be required to substantially increase capital expenditures or operating or decommissioning costs at our nuclear facilities to the extent there is a change in the Atomic Energy Act or the applicable regulations or the environmental rules and regulations applicable to nuclear facilities; a modification, suspension or revocation of licenses issued by the NRC; the imposition of civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities or the shutdown of one of our nuclear facilities. Any such event could have a material adverse effect on our financial position or results of operations.

Operational Risk—Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. In April 2016, during a scheduled refueling outage at Salem Unit 1, a visual inspection revealed degradation to a number of bolts inside the reactor vessel. The required bolt replacement significantly extended the duration of the outage. We expect to continue to inspect and replace degraded bolts at both Salem units over the next several refueling outage cycles and are developing a strategy to maintain the long-term health of both reactor vessel internals. Any significant outages could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.

In addition, if a station cannot be operated through the end of its current estimated useful life, our results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Nuclear Incident or Accident Risk—Accidents and other unforeseen problems have occurred at nuclear stations, both in the U.S. and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to operate unaffected units located at the same site, which would further affect our financial condition, results of operations and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages. Further, as a licensed nuclear operator subject to the Price-Anderson Act and a member of a nuclear industry mutual insurance company, Power is subject to potential retroactive assessments as a result of a nuclear incident or retroactive adverse loss experience.

In the event of non-compliance with applicable legislation, regulation and licenses, the NRC may increase regulatory oversight, impose fines, and/or shut down a unit, depending on its assessment of the severity of the non-compliance. If a serious nuclear incident were to occur, our business, reputation, financial condition and results of operations could be materially adversely affected. In each case, the amount and types of insurance commercially available to cover losses that might arise in connection with the operation of our nuclear fleet are limited and may be insufficient to

cover any costs we may incur.
We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.
The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed, particularly in light of the change in administration following the 2016 U.S. presidential election. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation has historically been located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's locational capacity market

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design rules and ISO-NE's forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In 2011, New Jersey enacted a law that provided for the construction of subsidized electric power generation. While this legislation was subsequently invalidated as unconstitutional, future state actions in New Jersey and elsewhere to subsidize the construction of new generation could have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis.

We could also be impacted by a number of other events, including regulatory or legislative actions such as direct and indirect subsidies, favoring non-competitive markets and/or technologies and energy efficiency and demand response initiatives. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and federal regulatory and political arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's capacity and energy revenues could be adversely affected. Moreover, through changes encouraged by FERC to transmission planning processes, or through RTO/ISO initiatives to change their planning processes, such as the recently accepted multi-driver project category in PJM, more transmission may ultimately be built to facilitate renewable generation or support other public policy initiatives. Any such addition to the transmission system could have a material adverse impact on our financial condition and results of operations.

We are subject to numerous federal, state and local environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive federal, state and local environmental laws and regulations regarding air quality, water quality, site remediation, land use, waste disposal, the impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. We expect there will be changes to existing environmental laws and regulations, particularly in light of the change in administration following the 2016 U.S. presidential election. Changes in these laws, or violations of laws, could result in significant increases in our compliance costs, capital expenditures to bring our facilities into compliance, operating costs for remediation and clean-up actions, civil penalties or damages from actions brought by third parties for alleged health or property damages. Any such increase in our costs could have a material impact on our financial condition, results of operations and cash flows and could require further economic review to determine whether to continue operations or decommission an affected facility. We may also be unable to successfully recover certain of these cost increases through our existing regulatory rate structures, in the case of PSE&G, or our contracts with our customers, in the case of Power.

Environmental laws and regulations have generally become more stringent over time, and this trend is likely to continue. In particular:

Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG emissions produced by our fossil generation facilities—Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. For example, in 2015 the EPA published new rules for both new and existing power plants. We may be required to incur significant costs to comply with these regulations and to continue operation of our fossil generation facilities, which could include the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities.

In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving us could be material to the future liability of energy companies. If relevant federal or state common law were to develop that imposed liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material.

Potential closed-cycle cooling requirements—In 2014, the EPA finalized rules regarding the regulation of cooling water intake structures. The EPA did not mandate closed cycle cooling as the BTA. Instead, the EPA set a fish impingement mortality standard that relies on a technology-based approach. The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. State actions to renew permits under the provisions of this rule are ongoing at this time. If the NJDEP or the CTEEP were to require installation of closed-cycle cooling or its equivalent at any of our Salem, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and cash flows and would require further economic review to determine whether to continue operations or decommission any such station.

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Remediation of environmental contamination at current or formerly-owned facilities—We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. In addition, the historic operations of our companies and the operations of numerous 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. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We are also involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. New Jersey law places affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances, impacting the speed by which we will need to investigate contaminated properties, which could adversely impact cash flows. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. However, exposure to natural resource damages could subject us to additional potentially material liability. For a discussion of these and other environmental matters, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

We may not receive necessary licenses and permits in a timely manner or at all, which could adversely impact our business and results of operations.

We must periodically apply for licenses and permits from various regulatory authorities, including environmental regulatory authorities, and abide by their respective orders. Delay in obtaining, or failure to obtain and maintain, any permits or approvals, including environmental permits or approvals, or delay in or failure to satisfy any applicable regulatory requirements, could:

- prevent construction of new facilities,
- limit or prevent continued operation of existing facilities,
- limit or prevent the sale of energy from these facilities, or
- result in significant additional costs,

each of which could materially affect our business, financial condition, results of operations and cash flows. In addition, the process of obtaining licenses and permits from regulatory authorities may be delayed or defeated by concerted community opposition and such delay or defeat could have a material effect on our business.

We cannot predict the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim relating to our business activities. An adverse determination could negatively impact our financial condition, results of operations and cash flows.

From time to time we are involved in legal, regulatory and other proceedings or claims arising out of our business operations, the most significant of which are summarized in Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities. Adverse outcomes in any of these proceedings could require significant expenditures that could have a material adverse effect on our financial condition, results of operations and cash flows.

In particular, as previously disclosed, Power has 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 and self-reported the errors to FERC, PJM and the PJM Independent Market Monitor (IMM). FERC Staff initiated a preliminary, non-public staff investigation into the matter, which is ongoing. We are unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG’s legal arguments. If we do not prevail in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to our results of operations.

Changes in tax law and regulation and the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact our results of operations and cash flows.

There exists the potential for comprehensive tax reform in the U.S. that may significantly change the tax rules applicable to domestic businesses, including changes that may impact investment incentives, deductions for depreciation, interest or otherwise, and dividends. We cannot assess what the overall effect of such potential legislation could be on our results of operations or cash flows. In addition, we are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes. These judgments can include reserves for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. If our actual tax obligations materially differ from our estimated obligations, our results of operations and cash flows could be materially adversely affected.

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OPERATIONAL RISKS

Because PSEG is a holding company, its ability to meet its corporate funding needs, service debt and pay dividends could be limited.

PSEG is a holding company with no material assets other than the stock or membership interests of its subsidiaries. Accordingly, all of the operations of PSEG are conducted by its subsidiaries, which are separate and distinct legal entities that have no obligation, contingent or otherwise, to pay the debt of PSEG or to make any funds available to PSEG to pay such debt or satisfy its other corporate funding needs. These corporate funding needs include PSEG's operating expenses, the payment of interest on and principal of its outstanding indebtedness and the payment of dividends on its capital stock. As a result, PSEG can give no assurances that its subsidiaries will be able to transfer funds to PSEG to meet all of these obligations.

Lack of growth or slower growth in the number of customers, or a decline in customer demand, could adversely impact our financial condition, results of operations and cash flows.

Growth in customer accounts and growth of customer usage each directly influence demand for electricity and the need for additional generation, transmission and distribution facilities. Customer growth and customer usage may be affected by a number of factors, including:

- regulatory incentives to reduce energy consumption;
- mandated energy efficiency measures;
- demand-side management tools;
- technological advances; and
- a shift in the composition of our customer base from commercial and industrial customers to residential customers.

Some or all of these factors could result in a lack of growth or decline in customer demand for electricity and may prevent us from fully realizing the benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows.

There may be periods when Power may not be able to meet its commitments under forward sale obligations at a reasonable cost or at all.

A substantial portion of Power's generation output has been sold forward under fixed price power sales contracts and Power also sells forward the output from its intermediate and peaking facilities when it deems it commercially advantageous to do so. Our forward sales of energy and capacity assume sustained, acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, information technology, processes or management effectiveness;
- disruptions in the transmission of electricity;
- labor disputes or work stoppages;
- fuel supply interruptions;
- transportation constraints;
- limitations which may be imposed by environmental or other regulatory requirements; and
- operator error, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity. Because the obligations under most of these agreements are not contingent on a unit being available to generate power, Power is generally required to deliver power to the buyer, even in the event of a plant outage, fuel supply disruption or a reduction in the available capacity of the unit. To the extent that Power does not have sufficient lower cost capacity to meet its commitments under its forward sale obligations, Power would be required to supply replacement power either by running its other higher cost power plants or by obtaining power from third-party sources at market prices that could substantially exceed the contract price. This could have a material adverse effect on our financial condition, results of operations and cash flows. If Power fails to deliver the contracted power, it would be required to pay the difference between the market price at the delivery point and the contract price, and the amount of such payments could be substantial.

In addition, as market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited.

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Certain of our generation facilities rely on transmission facilities that we do not own or control and that may be subject to transmission constraints. Our inability to maintain adequate transmission capacity could restrict our ability to deliver wholesale electric power to our customers and we may either incur additional costs or forego revenues. Conversely, improvements to certain transmission systems could also reduce revenues.

We depend on transmission facilities owned and operated by others to deliver the wholesale power we sell from our generation facilities. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be adversely impacted. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

In addition, in certain of the markets in which we operate, energy transmission congestion may occur and we may be deemed responsible for congestion costs if we schedule delivery of power between congestion zones during times when congestion occurs between the zones. If we were liable for such congestion costs, our financial results could be adversely affected.

A portion of our generation is located in load pockets. Expansion of transmission systems to reduce or eliminate these load pockets could negatively impact the value or profitability of our existing generation facilities in these areas.

Inability to successfully develop or construct generation, transmission and distribution projects could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits; construction and/or acquisition of additional generation units and transmission and distribution facilities; and modernizing existing infrastructure pursuant to investment programs entitled to current recovery. Currently, we have several significant projects underway or being contemplated.

The successful construction and development of these projects will depend, in part, on our ability to:

- obtain necessary governmental and regulatory approvals;
- obtain environmental permits and approvals;
- obtain community support for such projects to avoid delays in the receipt of permits and approvals from regulatory authorities;
- complete such projects within budgets and on commercially reasonable terms and conditions;
- obtain any necessary debt financing on acceptable terms and/or necessary governmental financial incentives;
- ensure that contracting parties, including suppliers, perform under their contracts in a timely and cost effective manner; and
- at PSE&G, recover the related costs through rates.

Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows. Further, any unexpected failure of our existing facilities, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures could result in reduced profitability. Modifications to existing facilities may require us to install the best available control technology or to achieve the lowest achievable emission rates required by then-current regulations, which would likely result in substantial additional capital expenditures.

In addition, the successful operation of new or upgraded generation facilities or transmission or distribution projects is subject to risks relating to supply interruptions; work stoppages and labor disputes; weather interferences; unforeseen engineering and environmental problems, including those related to climate change; and the other risks described herein. Any of these risks could cause our return on these investments to be lower than expected or they could cause these facilities to operate below expected capacity or availability levels, which would adversely impact our financial condition and results of operations through lost revenue, increased expenses, higher maintenance costs and penalties.

FERC Order 1000 has generally opened transmission development to competition from independent developers, allowing such developers to compete with incumbent utilities for the construction and operation of transmission facilities in its service territory. While Order 1000 retains limited carve-outs for certain projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents' use of their rights-of-way, increased competition for transmission projects could decrease the value of new investments that would be subject to recovery by PSE&G under its rate base, which could have a material adverse impact on our financial condition and results of operations. In addition, certain PJM cost allocation determinations have been

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recently challenged at FERC, the resolution of which could impact costs borne by New Jersey ratepayers and increase customer bills.

We may be adversely affected by equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers and remain competitive and could result in substantial financial losses.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are exposed to the risk of equipment failures, accidents, severe weather events, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. For instance, equipment failures in our natural gas distribution could give rise to a variety of hazards and operating risks, such as leaks, accidental explosions and mechanical problems, which could cause substantial financial losses and harm our reputation.

In addition, the physical risks of severe weather events, such as experienced from Hurricane Irene and Superstorm Sandy, and of climate change, changes in sea level, temperature and precipitation patterns and other related phenomena have further exacerbated these risks. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues; increase costs to repair and maintain our systems; subject us to potential litigation and/or damage claims, fines/penalties; and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could adversely affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow. For our transmission and distribution business, the cost of storm restoration efforts may not be fully recoverable through the regulatory process.

We own less than a controlling interest in some of our generating facilities.

We have limited control over the operation of some of our generating facilities, including the Keystone, Conemaugh and Peach Bottom facilities, because our investments represent less than a controlling interest. We seek to exert a degree of influence with respect to the management and operation of projects in which we own less than a controlling interest by negotiating to obtain positions on management committees or to receive certain limited governance rights. However, we may not always succeed in such negotiations. As a result, we may be dependent on our partners to operate such facilities. The approval of our partners also may be required for us to transfer our interest in such projects. Reliance on our partners for the management and operation of these facilities could result in a lower return on these facilities than what we believe we could have otherwise achieved.

Any inability to recover the carrying amount of our assets and leveraged leases could result in future impairment charges which could have a material adverse impact on our financial condition and results of operations.

Long-lived assets represent approximately 74%, 79% and 70% of the total assets of PSEG, PSE&G and Power, respectively, as of December 31, 2016. Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation business climate or market conditions, including prolonged periods of adverse commodity and capacity prices, could potentially indicate an asset’s or group of assets’ carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

Energy Holdings 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. As an equity investor, Energy Holdings’ equity investments in the leases are comprised of the total expected lease receivables 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. Our receipt of payments related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors, including new environmental legislation regarding air quality and other discharges in the process of generating electricity; market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments; overall financial condition of lease counterparties; and the quality and condition of assets under lease.

During the third quarter of 2016, in connection with Energy Holdings' annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases, it was determined that the revised residual value estimates for such leases were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016. During the fourth quarter of 2016, Energy Holdings recorded a $10 million pre-tax charge reflecting its best estimate of loss as a result of the current liquidity issues facing REMA.

In addition, REMA's parent company, GenOn Energy, Inc. (GenOn), reported in August 2016 that it did not expect to have sufficient liquidity to repay their senior unsecured notes due in June 2017. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related

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impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments, which could include further write-downs of the values of Energy Holdings' leveraged leases.

There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Inability to maintain sufficient liquidity in the amounts and at the times needed or access sufficient capital at reasonable rates or on commercially reasonable terms could adversely impact our business.

Funding for our investments in capital improvement and additions, scheduled payments of principal and interest on our existing indebtedness and the extension and refinancing of such indebtedness has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and depend on our ability to generate cash in the future from our operations and continued access to capital and credit markets to efficiently fund our cash flow needs. Our ability to generate cash flow is dependent upon, among other things, industry conditions and general economic, financial, competitive, legislative, regulatory and other factors. The ability to arrange financing and the costs of such financing depend on numerous factors including, among other things.

- general economic and capital market conditions;
- the availability of credit from banks and other financial institutions;
- tax, regulatory and securities law developments;
- for PSE&G, our ability to obtain necessary regulatory approvals for the incurrence of additional indebtedness;
- investor confidence in us and our industry;
- our current level of indebtedness and compliance with covenants in our debt agreements;
- the success of current projects and the quality of new projects;
- our current and future capital structure;
- our financial performance and the continued reliable operation of our business; and
- maintenance of our investment grade credit ratings.

Market disruptions, such as economic downturns experienced in the U.S. and abroad in recent years, the bankruptcy of an unrelated energy company, changes in market prices for electricity and gas, and actual or threatened terrorist attacks, may increase our cost of borrowing or adversely affect our ability to access capital. As a result, no assurance can be given that we will be successful in obtaining financing for projects and investments, to extend or refinance maturing debt or for our other cash flow needs on acceptable terms or at all, which could materially adversely impact our financial position, results of operations and future growth.

In addition, if Power were to lose its investment grade credit rating from S&P or Moody's, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows.

We may be unable to realize anticipated tax benefits or retain existing tax credits.

The deferred tax assets and tax credits of PSEG, PSE&G or Power are evaluated for ultimate ability to realize these assets. A valuation allowance may be recorded against the deferred tax assets if we estimate that such assets are more likely than not to be unrealizable based on available evidence including cumulative and forecasted pretax book earnings at the time the estimate is made. A valuation allowance related to deferred tax assets or the monetization of tax credits can be affected by changes to tax laws, statutory tax rates and future taxable income levels. In the event that we determine that we would not be able to realize all or a portion of our deferred tax assets in the future or the benefit of tax credits, we would reduce such amounts through a charge to income tax expense in the period in which that determination was made, which could have a material adverse impact on our financial condition and results of operations.

Challenges associated with retention of key executives and a skilled workforce could adversely impact our businesses.

Our operations depend on the retention of key executives and a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. We may incur increased costs for contractors to replace employees, and the loss of institutional and industry knowledge and the increased costs to hire and lengthy time to train new personnel could result in lower productivity, resulting in increased costs, which would negatively impact our results of operations. This has the potential to become more critical as a growing number of employees become eligible to retire.

As of December 31, 2016, approximately 62% of our employees were covered by collective bargaining agreements. As a result, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result

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in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Covenants in our debt instruments may adversely affect our operations.

PSEG's, PSE&G's and Power's debt instruments contain events of default customary for financings of their type, including cross accelerations to other debt of that entity and, in the case of PSEG's and Power's bank credit agreements, certain change of control events. Power's bank credit agreements and outstanding notes also contain limitations on the incurrence of subsidiary debt and liens and Power's outstanding notes require Power to repurchase such notes upon certain change of control events. Our ability to comply with these covenants may be affected by events beyond our control. If we fail to comply with the covenants and are unable to obtain a waiver or amendment, or a default exists and is continuing under such debt, the lenders or the holders or trustee of such debt, as applicable, could give notice and declare outstanding borrowings and other obligations under such debt immediately due and payable. We may not be able to obtain waivers, amendments or alternative financing, or if obtainable, it could be on terms that are not acceptable to us. Any of these events could adversely impact our financial condition, results of operations and cash flows.

Cybersecurity attacks or intrusions could adversely impact our businesses.

We own and/or operate generating stations and transmission and distribution facilities, all of which are dependent on the operation of our information technology systems. Our ability to market our generation output and acquire and hedge fuel and power are also dependent on our information technology systems as well as information technology systems owned and operated by third parties, such as ISOs and RTOs. Our and third-party information technology systems may be impacted by cybersecurity attacks or hostile technological intrusions involving domestic or foreign sources (including nation states and special interest groups) or inadvertent disclosure of company and/or customer information. A cybersecurity attack may also leverage such information technology to cause disruptions at a third party. Cybersecurity threats to our operations include:

- disruption of the operation of our assets and the power grid,
- theft of confidential company, employee, shareholder, vendor or customer information,
- general business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues or the ability to record, process and/or report financial information correctly, and
- breaches of vendors' infrastructures where our confidential information is stored.

We have experienced and expect to continue to experience actual or attempted cyber-attacks on our information technology systems. However, none of these actual or attempted cyber-attacks has had a material impact on our operations or financial condition. If a significant cybersecurity event or breach should occur, we could (i) experience disruptions to our business, property damage, theft of unauthorized access to customer or other information; (ii) experience significant loss of revenue or incur material costs for repair, remediation and breach notification and increased capital and operating costs to implement increased security measures; and (iii) be subject to increased regulation, litigation and reputational damage. Similarly, a significant cybersecurity event or breach experienced by a competitor, regulatory authority, RTO or ISO could also materially impact our business and results of operations. Experiencing a cybersecurity incident could also cause us to be non-compliant with applicable laws and regulations, including those promulgated by the NRC and NERG, or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings, regulatory fines and increased scrutiny and possible damage to our reputation and brand, resulting in a reduction in customer confidence.

The market for cybersecurity insurance is relatively new and coverage available for cybersecurity events may evolve as the industry matures. While we maintain insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage we experience.

Acts of war or terrorism could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial and insurance market instability and volatility in power and fuel markets, which could materially adversely affect our business and results of operations, including our ability to access capital on terms and conditions acceptable to us. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities and information technology systems, could be direct or indirect targets or be affected by terrorist or other criminal activity. Such events could severely disrupt our business operations and prevent us from servicing our customers. New or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, PSE&G and Power

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None.

ITEM 2. PROPERTIES
Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.
Generation Facilities
Power
As of December 31, 2016, Power's share of installed fossil and nuclear generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
Steam:					
Hudson (A)	NJ	565	100%	565	Coal/Gas
Mercer (A)	NJ	632	100%	632	Coal/Gas
Sewaren	NJ	445	100%	445	Gas
Keystone (B)	PA	1,711	23%	391	Coal
Conemaugh (B)	PA	1,711	23%	385	Coal
Bridgeport Harbor	CT	383	100%	383	Coal
New Haven Harbor	CT	448	100%	448	Oil/Gas
Total Steam		5,895		3,249	
Nuclear:					
Hope Creek	NJ	1,172	100%	1,172	Nuclear
Salem 1 & 2	NJ	2,296	57%	1,318	Nuclear
Peach Bottom 2 & 3 (C)	PA	2,450	50%	1,225	Nuclear
Total Nuclear		5,918		3,715	
Combined Cycle:					
Bergen	NJ	1,229	100%	1,229	Gas/Oil
Linden	NJ	1,230	100%	1,230	Gas/Oil
Bethlehem	NY	757	100%	757	Gas
Kalaeloa	HI	208	50%	104	Oil
Total Combined Cycle		3,424		3,320	
Combustion Turbine:					
Essex	NJ	81	100%	81	Gas/Oil
Kearny	NJ	456	100%	456	Gas/Oil
Burlington	NJ	168	100%	168	Gas/Oil
Linden	NJ	336	100%	336	Gas/Oil
New Haven Harbor	CT	129	100%	129	Gas/Oil
Bridgeport Harbor	CT	17	100%	17	Oil
Total Combustion Turbine		1,187		1,187	
Pumped Storage:					
Yards Creek (D)	NJ	420	50%	210	
Total Power Plants		16,844		11,681	

(A)

In October 2016, Power determined that it would cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements for additional information.

(B) Operated by GenOn Northeast Management Company.

(C) Operated by Exelon Generation.

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(D) Operated by Jersey Central Power & Light Company.

As of December 31, 2016, Power also owned and operated 326 MW dc of photovoltaic solar generation facilities in various states.

PSE&G

Primarily all of PSE&G’s property is located in New Jersey and PSE&G’s First and Refunding Mortgage, which secures the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G’s property. PSE&G’s electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

Electric Property and Facilities

As of December 31, 2016, PSE&G’s electric transmission and distribution system included approximately 24,000 circuit miles, and 851,000 poles, of which 65% are jointly-owned. In addition, PSE&G owns and operates 47 switching stations with an aggregate installed capacity of 30,037 megavolt-amperes (MVA) and 246 substations with an aggregate installed capacity of 8,179 MVA. Four of those substations, having an aggregate installed capacity of 109 MVA are operated on leased property. In addition, PSE&G owns four electric distribution headquarters and five electric sub-headquarters.

Gas Property and Facilities

As of December 31, 2016, PSE&G’s gas system included approximately 18,000 miles of gas mains, 12 gas distribution headquarters, two sub-headquarters, and one meter shop serving all of its gas territory in New Jersey. In addition, PSE&G operates 61 natural gas metering and regulating stations, of which 25 are located on land owned by customers or natural gas pipeline suppliers and are operated under lease, easement or other similar arrangement. In some instances, the pipeline companies own portions of the metering and regulating facilities. PSE&G also owns one liquefied natural gas (LNG) and three liquid petroleum air gas (LPG) peaking facilities. The daily gas capacity of these peaking facilities (the maximum daily gas delivery available during the three peak winter months) is approximately 2.8 million therms in the aggregate.

Solar

As of December 31, 2016, PSE&G had 123 MW dc of installed solar capacity throughout New Jersey.

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ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business—Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Ewing Explosion

In 2014, pursuant to an existing contract, PSE&G assigned Henkels and McCoy (Henkels) to replace the electrical service at a home in the South Fork Townhouse Community in Ewing Township, Mercer County, New Jersey. As Henkels began work to install new electric service, a gas explosion occurred in the townhouse community resulting in damage to numerous properties, personal injuries and one fatality.

Twenty-two lawsuits have been filed to date relating to the gas explosion, of which PSE&G was named as a defendant in nineteen cases. To date, six of these cases have resolved through private negotiations and/or mediation. In one of the remaining pending matters, plaintiffs representing the estate of the decedent are seeking damages under the New Jersey Wrongful Death Act and the New Jersey Survivors Act as well as punitive damages. PSE&G has denied all allegations of liability. We intend to continue to vigorously defend these lawsuits. At this stage of the litigation, we are unable to determine or predict the ultimate outcome of any of the remaining lawsuits. Henkels has agreed to indemnify PSE&G for all compensatory damages awarded as a result of this incident unless it is proven that PSE&G is solely responsible. Any award for punitive damages against PSE&G would not be covered by such indemnity.

Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on our financial condition, results of operations or net cash flows.

(1) Claim by the EPA, Region III, under CERCLA with respect to the Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and the former and current site owners are alleged to be liable for contamination at the site and PSE&G has been named as a Potentially Responsible Party (PRP). The EPA approved the Final Revised Remedial Design for the Site in early 2008. This document presented the design details of the EPA's selected remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement the negotiated EPA selected remedy. The EPA settled its claims against the site owners who did not join the Consent Decree to implement the remedy. The PRP group's implementation of the remedy was completed in 2010; however, an additional estimated cost of $200,000 was incurred by PSE&G in 2016 to repair part of the remedy. Although the PRP Group has not received a formal Certification of Completion of the Remedy from the EPA, the PRP Group does not anticipate further significant costs at this time. Although subject to EPA approval and oversight, long-term monitoring, operations, and maintenance activities are anticipated through 2018 at a total estimated cost to PSE&G of $200,000.

(2) The EPA sent PSE&G, Power and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry's Creek in Bergen County, New Jersey and requesting that the PRPs perform a Remedial Investigation and Feasibility Study (RI/FS) on Berry's Creek and the connected tributaries and wetlands. Berry's Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could cost approximately $18 million. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent in 2008 to conduct the RI/FS, which is estimated to be completed in 2017/2018.

(3) In January 2010, we, as the current owner of the Gates Construction Corporation Landfill, received a letter from the NJDEP asserting that the subject landfill has not been properly closed in accordance with the NJDEP Solid Waste Regulations. Power has retained an environmental consultant to prepare a closure plan acceptable to the NJDEP.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange, Inc. As of February 17, 2017, there were 63,718 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2011 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2011	2012	2013	2014	2015	2016
PSEG	$100.00	$96.96	$106.03	$142.26	$138.12	$162.47
S&P 500	$100.00	$115.93	$153.39	$174.30	$176.76	$197.77
DJ Utilities	$100.00	$101.59	$114.46	$149.35	$144.84	$170.94
S&P Electrics	$100.00	$101.24	$114.61	$147.63	$140.53	$163.20

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend per Share
2016			
First Quarter	$47.22	$37.85	$ 0.41
Second Quarter	$47.41	$42.77	$ 0.41
Third Quarter	$46.81	$41.07	$ 0.41
Fourth Quarter	$44.29	$39.28	$ 0.41
2015			
First Quarter	$44.45	$39.00	$ 0.39
Second Quarter	$43.97	$38.93	$ 0.39
Third Quarter	$43.91	$38.16	$ 0.39
Fourth Quarter	$44.18	$36.80	$ 0.39

On February 21, 2017, our Board of Directors approved a $0.43 per share common stock dividend for the first quarter of 2017. This reflects an indicative annual dividend rate of $1.72 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.
The following table indicates our common share repurchases in the open market during the fourth quarter of 2016 to satisfy obligations under various equity compensation award grants:

Three Months Ended December 31, 2016	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$ —
November 1-November 30	127,128	$ 40.97
December 1-December 31	30,000	$ 41.42

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2016:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Long-Term Incentive Plan	1,029,900	$ 37.93	14,517,886
Employee Stock Purchase Plan	—	—	3,463,447
Total	1,029,900	$ 37.93	17,981,333

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data—Note 18. Stock Based Compensation.

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G's ability to continue to pay dividends, see Item 7. MD&A—Liquidity and Capital Resources.

Power

We own all of Power's outstanding limited liability company membership interests. For additional information regarding Power's ability to pay dividends, see Item 7. MD&A—Liquidity and Capital Resources.

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ITEM 6. SELECTED FINANCIAL DATA
PSEG
The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG					
Years Ended December 31,	2016	2015	2014	2013	2012
	Millions, except Earnings per Share				
Operating Revenues (A)	$9,061	$10,415	$10,886	$9,968	$9,781
Income from Continuing Operations (B)	$887	$1,679	$1,518	$1,243	$1,275
Net Income	$887	$1,679	$1,518	$1,243	$1,275
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$1.76	$3.32	$3.00	$2.46	$2.52
Diluted (A)	$1.75	$3.30	$2.99	$2.45	$2.51
Net Income					
Basic	$1.76	$3.32	$3.00	$2.46	$2.52
Diluted	$1.75	$3.30	$2.99	$2.45	$2.51
Dividends Declared per Share	$1.64	$1.56	$1.48	$1.44	$1.42
As of December 31,					
Total Assets	$40,070	$37,535	$35,287	$32,480	$31,694
Long-Term Obligations (C)	$10,897	$8,837	$8,218	$7,830	$6,670

(A) Operating Revenues for 2016, 2015 and 2014 includes $410 million, $375 million and $389 million, respectively, for Long Island Electric Utility Servco, LLC (Servco), a wholly owned subsidiary of PSEG Long Island LLC (PSEG LI). See Item 8. Financial Statements and Supplementary Data—Note 4. Variable Interest Entities for additional information.

(B) Income from Continuing Operations includes after-tax expenses of $396 million related to the early retirement of Power’s Hudson and Mercer coal/gas generation plants and after-tax charges totaling $92 million related to investments in NRG REMA, LLC’s leveraged leases for 2016 and an after-tax insurance recovery for Superstorm Sandy of $102 million for 2015. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements, Note 7. Long-Term Investments and Note 8. Financing Receivables for additional information for 2016.

(C) Includes capital lease obligations.

PSE&G and Power
Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 7. 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—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the 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, and
- Power—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) 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.

Our business discussion in Item 1. Business 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 Item 1A. Risk Factors provides information about factors that could have a material adverse impact on our businesses. The following discussion provides an overview of the significant events and business developments that have occurred during 2016 and key factors that we expect may drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the related Notes to the Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

EXECUTIVE OVERVIEW OF 2016 AND FUTURE OUTLOOK

2016 Overview

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:

- improving utility operations through growth in investment in T&D and other infrastructure projects designed to enhance system reliability and resiliency and to meet customer expectations and public policy objectives,
- 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 years ended December 31, 2016 and 2015 are presented below:

	Years Ended December 31,	
	2016	2015
Earnings (Losses)	Millions, except per share data	
PSE&G	$889	$787
Power	18	856
Other	(20)	36
PSEG Net Income	$887	$1,679
PSEG Net Income Per Share (Diluted)	$1.75	$3.30

Our 2016 over 2015 decrease in Net Income was due primarily to charges related to the early retirement of our Hudson and Mercer units, mark-to-market (MTM) losses in 2016 as compared to gains in 2015, lower volumes of electricity and gas sold at lower average realized sales prices, lower capacity and operating reserve revenues, storm insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy, and charges in 2016 related to investments in certain leveraged leases at Energy Holdings. These decreases were partially offset by higher transmission revenues, lower generation costs and higher costs incurred at Power for planned outages in 2015, and higher management fee revenues at PSEG LI pursuant to the OSA. For a more detailed discussion of our financial results, see Results of Operations.

During 2016, we maintained a strong balance sheet. We continued to effectively deploy capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results, which when combined with the cash flow generated by Power, our merchant generator and power marketer, has allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, we continue to invest in transmission projects that focus on reliability improvements and replacement of aging infrastructure. We also continue to make investments to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014 and to seek recovery on such investments. We also commenced modernizing PSE&G’s gas distribution systems as part of our Gas System Modernization Program (GSMP) that was approved by the BPU in late 2015. Over the past few years, these types of investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G. In 2017, as a result of our Energy Strong Order from the BPU, we will be required to file a distribution base rate case proceeding. We cannot predict the impact such proceeding will have on our distribution business.

Despite the unseasonable warm winter weather patterns in 2016, Power’s results benefited from access to natural gas supplies through existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G’s customers through the BGSS arrangement. The contracts are sized to provide for 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. Alternatively, gas supply and pipeline capacity constraints could adversely impact our ability to meet the needs of our utility customers and generating units. Power’s hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. More than half of Power’s expected gross margin in the upcoming year relates to our hedging strategy, our expected revenues from the capacity market mechanisms and certain ancillary service payments such as reactive power.

Our investments in the latter half of 2015 and early 2016 in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. See Item 1. Business—Power for additional information on major growth projects. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and are expected to contribute to the overall efficiency of operations.

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced as being at risk for early retirement. This situation is generally due to low natural gas prices resulting from the growth of shale gas production since 2007, the continuing cost of regulatory compliance for nuclear facilities and both federal and state-level policies that provide credits to renewable energy such as wind and solar, but do not apply to

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nuclear generating stations. These trends have significantly reduced the revenues to nuclear generating stations while simultaneously raising the unit cost of production. This may result in the electric generation industry experiencing a shift from nuclear generation to natural gas-fired generation, creating greater reliance on natural gas pipelines for delivery and less diversity of the generation fleet.

If trends noted above continue or worsen, our nuclear generating units could cease being economically competitive which may cause us to retire such units prior to the end of their useful lives. The costs associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, accelerated asset retirement costs, severance costs and environmental remediation costs, could be material. We continue to advocate for sound policies that recognize nuclear power as a source of clean energy and an important part of a diverse and reliable energy portfolio.

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

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 in New Jersey. In February 2016, FERC issued an order granting PSE&G’s request that it be permitted to seek recovery of 100% of its portion of the project’s costs to address identified high voltage issues at Artificial Island in New Jersey if the project is canceled for reasons beyond PSE&G’s control. In April 2016, PSE&G accepted construction responsibility for the three components of the project that PJM assigned to it, based on having reached agreement with PJM regarding an estimate for the project base cost of $273 million, plus risk and contingency for a total project cost of up to $340 million. In August 2016, PJM announced that it had suspended the Artificial Island transmission project and would be performing a comprehensive analysis to support a future course of action. PJM will submit its final recommendation to the PJM Board at the April 2017 Board meeting.

In April 2016, PJM filed at FERC to incorporate a voltage threshold into PJM’s Regional Transmission Expansion Plan (RTEP) process to exempt, except under certain circumstances, reliability violations on facilities below 200 kV from PJM’s proposal window process. We generally support this reform as a measure to improve the efficiency of the open window procedure that will permit transmission developers to focus on the projects most likely to benefit from a competitive process.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G’s ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G’s future capital investments. In addition, as a basic generation service (BGS) supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers may be entitled to an adjustment, subject to BPU approval. We do not believe that these matters will have a material effect on Power’s business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners’ base return on equity (ROE). Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners’ base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G’s transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In June 2015, FERC conditionally accepted a proposal from PJM for a capacity performance product to include

generators, Demand Response and energy efficiency providers, which will be required to perform during emergency conditions, as a supplement to the base capacity product. The proposal included enhanced performance-based incentives and penalties. We believe that the auction pricing adequately reflects the increased costs that could result from operating under more stringent rules for generation availability. Based on the auction results, the capacity performance 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 and financial risks. Appeals of FERC's capacity performance orders are pending.
In May 2016, PJM announced the results of the RPM capacity auction for the 2019-2020 delivery year. Power cleared 8,895 MW of its generating capacity at an average price of $116 per MW-day for the 2019-2020 delivery period. Of the cleared

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capacity, Power believes that nearly all is compliant with PJM's capacity performance requirements. In the two prior capacity auctions covering the 2017-2018 and 2018-2019 delivery years, Power cleared approximately 8,700 MW at average prices of $177 per MW-day and $215 per MW-day, respectively. Prices in the most recent auction reflect PJM's downwardly-revised demand forecast, changes in the capacity emergency transfer limits due to transmission expansion and the effects of both the new generation and uncleared generation from the prior year's auction.

As a result of the efforts of certain entities in PJM to obtain financial support arrangements from their state commission, a group of suppliers requested that FERC direct PJM to expand the currently effective "minimum offer price rule" to apply to certain existing units seeking subsidies. The suppliers' request was intended to avoid a scenario where the subsidized generators would submit bids into the PJM capacity market that did not reflect their actual costs of operation and could artificially suppress capacity market prices. We are currently awaiting FERC action on the suppliers' request and cannot predict the outcome of the proceeding.

See Item 1. Business—Federal Regulation for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

The U.S. Supreme Court's February 2016 decision to stay the implementation of the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act (CAA) for existing power plants, will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. In particular, the historic operations of PSEG companies and the operations of numerous 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. We are also currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, and the costs of any such remediation efforts could be material.

For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

FERC Compliance

Since September 2014, FERC Staff has been conducting a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. This investigation is ongoing. The amounts of potential disgorgement and other potential penalties that we may incur span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail, in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record losses that would be material to PSEG's and Power's results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Early Retirement of Hudson and Mercer Units

In October 2016, Power determined it will cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. The exact timing of the early retirement of these units may be impacted by operational and other conditions that could subsequently arise. The decision to retire the Hudson and Mercer units will have a material effect on PSEG's and Power's results of operations. In 2016, PSEG and Power recognized pre-tax charges in Energy Costs and Operation and Maintenance (O&M) of $62 million and $53 million, respectively, related to coal inventory adjustments, capacity penalties, materials and supplies inventory reserve adjustments for parts that cannot be used at other generating units, employee-related severance benefits costs and construction work in progress impairments, among other shut down items. In addition to these charges, Power recognized incremental Depreciation and Amortization during 2016 of $555 million ($571 million in total) and expects to recognize an additional $931 million ($958 million in total) in 2017 due to the significant shortening of the expected economic useful lives of Hudson and Mercer. Additional employee-related salary continuance and severance costs and various miscellaneous costs may also be incurred during the period prior to retirement. Finally, Power currently anticipates using the

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sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such remediation are neither currently probable nor estimable but may be material. For additional information, including our estimated costs through 2017, see Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements.

The primary factors considered during our annual five-year strategic planning process that contributed to the decision to retire these units early include significant declines in revenues and margin caused by a sustained period of depressed wholesale power prices and reduced capacity factors caused by lower natural gas prices making coal generation less economically competitive than natural gas-fired generation. Despite experiencing recent warmer than normal weather in PJM this summer, Power did not experience the usual increase in electricity prices in PJM as it had in past hot summers. This trend has a further adverse economic impact to these units because they generally dispatch and earn energy margin on peak hot and cold days. In addition, the upcoming PJM capacity auction in May 2017 will be the first to require all generating units to meet the increased operating performance standards of PJM’s new capacity performance construct. Power determined that the costs to upgrade the existing units at the Hudson and Mercer stations to be able to comply with these higher reliability standards are too significant and not economic given current market conditions.

In addition, PSEG and Power continue to monitor their other coal assets, including the Keystone and Conemaugh generating stations, to ensure their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG’s and Power’s control and may impact our ability to operate or maintain these assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG’s and Power’s future financial results.

Leveraged Lease Impairments

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. During the fourth quarter of 2016, Energy Holdings recorded a $10 million pre-tax charge in Operating Revenues reflecting its best estimate of loss as a result of the current liquidity issues facing REMA. There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.

Additional facilities in our leveraged lease portfolio include the Joliet and Shawville generating facilities, which were converted to use natural gas. However, these units may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. As a result, these facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged leases associated with these facilities.

Further, REMA’s parent company, GenOn Energy, Inc. (GenOn), reported in August 2016 that it did not expect to have sufficient liquidity to repay their senior unsecured notes due in June 2017. Although all lease payments are current, PSEG cannot predict the outcome of GenOn’s efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA. PSEG continues to monitor any changes to REMA’s and GenOn’s status and potential impacts on Energy Holdings’ lease investments, which could include further write-downs of the values of

Energy Holdings' leveraged leases. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

Salem Operations

The previously announced bolt replacement at Salem Unit 1 was completed and the unit returned to service on July 30, 2016. We expect to continue to inspect and replace degraded bolts at both Salem units over the next several refueling outage cycles. We are participating with the Electric Power Research Institute, the Nuclear Energy Institute and other operators of similarly-designed pressurized water reactors in developing a strategy to maintain the long-term health of the reactor vessel internals.

Extension of the Salem Unit 1 outage into July and an unplanned outage at Salem Unit 2 due to a transformer failure currently under investigation reduced output from the Salem units in the third quarter. This was partially offset by increased production at our Hope Creek and Peach Bottom units. As a result, our nuclear capacity factor for the year ended December 31, 2016 was 86.9%.

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Pension Plan Merger

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. As a result, we estimate that in 2017, the total net periodic benefit costs are expected to decrease by approximately $72 million or $48 million, net of amounts capitalized, as compared to the 2017 amounts that would have been recognized had the plans not been merged. This is due to the amortization period for gains and losses for the merged plan resulting in lower amortization than that of the individual plans. No changes were made to the benefit formulas, vesting provisions, or to the employees covered by the plans.

Pension and Other Postretirement Benefits—Change in Accounting Estimate

At the end of 2015, we changed the approach used to measure future service and interest costs for pension and other post-retirement benefits. For 2015 and prior, we calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, we have elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change did not affect the measurement of the plan obligations. As a change in accounting estimate, this change was reflected prospectively. We reduced 2016 pension and OPEB expense by approximately $34 million and $13 million, respectively, net of amounts capitalized.

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 opportunities in a rapidly evolving market as we remain diligent in managing costs. In 2016, our

- diverse fuel mix and dispatch flexibility allowed us to generate approximately 52 terra-watt hours while addressing fuel availability and price volatility and compensating for the extended outages at our Salem units,
- combined cycle fleet produced 16 terawatt hours at an average capacity factor of 57%, and
- utility was recognized for the fifteenth consecutive year as the most reliable utility in the Mid-Atlantic region.

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 2016 as we:

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2016 to $1.64 per share.

We expect to be able to fund our planned capital requirements, as described in Liquidity and Capital Resources, without the issuance of new equity.

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 2016, we

- made additional investments in transmission infrastructure projects,
- began executing our GSMP and continued executing Energy Strong and other existing BPU-approved utility programs,
- commenced construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and announced our plan to construct BH5 and commence operations in mid-2019, and
- acquired solar energy projects totaling 248 MW-direct current (dc), of which 177 MW dc are already in-service, primarily in North Carolina, Colorado and Utah. The remaining MW dc are scheduled to be in-service by the fourth quarter of 2017.

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Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-growing economy and a cost-constrained environment with low gas prices, 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 in response to changes in demand,
- execute our utility capital investment program, including our Energy Strong program, 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, Sewaren 7, BH5 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 2017 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,
- fair and timely rate relief from the BPU and FERC for recovery of costs and return on investments, including with respect to our distribution base rate case which must be filed with the BPU no later than November 1, 2017,
- the potential for comprehensive tax reform, particularly in light of public statements by the current U.S. administration and key members of Congress,
- uncertainty in the 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,
- the impact of lower natural gas prices and increasing environmental compliance costs on the competitiveness of our nuclear and remaining coal-fired generation plants, and the potential for retirement of such plants earlier than their current useful lives,
- 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,
- maintaining a diverse mix of fuels to mitigate risks associated with fuel price volatility and market demand cycles, and
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,

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- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

In 2016, Power announced its intention to develop a retail platform to sell physical electricity and natural gas, which we believe would complement our existing wholesale marketing business. Power was granted licenses in 2016 to sell both electricity and gas in the states of New Jersey and Pennsylvania.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

	Years Ended December 31,		
	2016	2015	2014
Earnings (Losses)	Millions		
PSE&G	$889	$787	$725
Power (A)	18	856	760
Other (B)	(20)	36	33
PSEG Net Income	$887	$1,679	$1,518
PSEG Net Income Per Share (Diluted)	$1.75	$3.30	$2.99

(A) Power's results in 2016 includes after-tax expenses of $396 million related to the early retirement of its Hudson and Mercer coal/gas generation plants. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements for additional information. Power's results in 2015 include an after-tax insurance recovery for Superstorm Sandy of $102 million.

(B) Other includes after-tax activities at the parent company, PSEG LI and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges totaling $92 million related to its investments in NRG REMA, LLC's leveraged leases in 2016. See Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments and Note 8. Financing Receivables for further information.

Our results include the realized gains, losses and earnings on Power's NDT Fund and other related NDT activity. Realized gains and losses, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income (Deductions), and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear ARO is recorded in O&M Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense. In 2014, we restructured portions of our NDT Fund and realized a pre-tax gain of $65 million.

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

The combined after-tax impact on Net Income for the years ended December 31, 2016, 2015 and 2014 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2016	2015	2014
	Millions, after tax		
NDT Fund and Related Activity (A)	$—	$ 8	$ 68

Non-Trading MTM Gains (Losses) (B)	$(100)	$ 93	$ 66

(A) Net of tax (expense) benefit of $(5) million, $(16) million and $(70) million for the years ended December 31, 2016, 2015 and 2014, respectively.

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(B) Net of tax (expense) benefit of $68 million, $(65) million and $(45) million for the years ended December 31, 2016, 2015 and 2014, respectively.

The 2016 year-over-year decrease in our Net Income was driven primarily by:

- charges related to the early retirement of two coal/gas generation units at Power (See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements),
- MTM losses in 2016 as compared to MTM gains in 2015,
- lower volumes of energy sold at lower average realized sales prices,
- lower capacity and operating reserve revenues in PJM,
- higher 2016 congestion costs in PJM due primarily to realized gains on financial transmission rights (FTR) in PJM in the prior year due to extremely cold weather,
- lower volumes of gas sold at lower average prices under the Basic Gas Supply Service (BGSS) contract,
- insurance recoveries received primarily by Power in 2015 related to Superstorm Sandy, and
- an impairment related to investments in certain leveraged leases at Energy Holdings (See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables).

These decreases were partially offset by:

- lower generation costs driven by lower fuel costs, particularly for natural gas, and reduced generation output at Power,
- higher costs incurred at Power for planned outages in 2015,
- higher transmission revenues, and
- higher management fee revenues at PSEG LI pursuant to the OSA.

The 2015 year-over-year increase in our Net Income was driven by:

- higher transmission revenues,
- lower generation costs due to lower fuel costs, primarily reflecting lower natural gas and coal prices,
- higher MTM gains in 2015, and
- insurance recoveries of Superstorm Sandy costs, primarily at Power.

These increases were partially offset by:

- lower capacity revenues resulting from lower average auction prices coupled with lower ancillary and operating reserve revenues in the PJM region,
- lower realized gains and higher other-than-temporary impairments related to the NDT Fund, and
- higher pension and OPEB costs, net of amounts capitalized.

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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 8. Financial Statements and Supplementary Data—Note 24. Related-Party Transactions.

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2016	2015	2014	2016 vs. 2015		2015 vs. 2014	
	Millions			Millions	%	Millions	%
Operating Revenues	$9,061	$10,415	$10,886	$(1,354)	(13)	$(471)	(4)
Energy Costs	3,001	3,261	3,886	(260)	(8)	(625)	(16)
Operation and Maintenance	3,008	2,978	3,150	30	1	(172)	(5)
Depreciation and Amortization	1,476	1,214	1,227	262	22	(13)	(1)
Income from Equity Method Investments	11	12	13	(1)	(8)	(1)	(8)
Other Income (Deductions)	124	152	229	(28)	(18)	(77)	(34)
Other-Than-Temporary Impairments	28	53	20	(25)	(47)	33	N/A
Interest Expense	385	393	389	(8)	(2)	4	1
Income Tax Expense	411	1,001	938	(590)	(59)	63	7

The 2016, 2015 and 2014 amounts in the preceding table for Operating Revenues and O&M costs each include $410 million, $375 million and $389 million, respectively, for Servco. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Item 8. Financial Statements and Supplementary Data—Note 4. Variable Interest Entities for further explanation. The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2016	2015	2014	2016 vs. 2015		2015 vs. 2014	
	Millions			Millions	%	Millions	%
Operating Revenues	$6,221	$6,636	$6,766	$(415)	(6)	$(130)	(2)
Energy Costs	2,567	2,722	2,909	(155)	(6)	(187)	(6)
Operation and Maintenance	1,475	1,560	1,558	(85)	(5)	2	—
Depreciation and Amortization	565	892	906	(327)	(37)	(14)	(2)
Other Income (Deductions)	79	75	58	4	5	17	29
Interest Expense	289	280	277	9	3	3	1
Income Tax Expense	515	470	449	45	10	21	5

Year Ended December 31, 2016 as compared to 2015

Operating Revenues decreased $415 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $191 million due primarily to an increase in transmission revenues.

- Transmission revenues were $223 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.

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- Electric distribution revenues decreased $27 million due primarily to $47 million in lower collections of Green Program Recovery Charges (GPRC), partially offset by an $18 million increase in Energy Strong revenues.
- Gas distribution revenues decreased $5 million due to a decrease of $43 million due to lower sales volumes and $7 million in lower collections of GPRC. These decreases were partially offset by higher Weather Normalization Clause (WNC) revenues of $25 million due to warmer weather in 2016 compared to 2015 and $20 million due to the inclusion of Energy Strong in base rates.

Clause Revenues decreased $445 million due to lower Securitization Transition Charge (STC) revenues of $419 million, lower Societal Benefit Charges (SBC) of $33 million, and lower Solar Pilot Recovery Charges (SPRC) of $8 million. These decreases were partially offset by higher Margin Adjustment Clause (MAC) revenues of $15 million. The changes in STC, SBC, SPRC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC, SPRC or MAC collections.

Commodity Revenues decreased $155 million due to lower Electric and Gas revenues. This is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $136 million due to $73 million in lower collections of Non-Utility Generation Charges (NGC) due primarily to lower prices, $42 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and $21 million in lower BGS revenues primarily due to lower sales volumes.
- Gas revenues decreased $19 million due to $80 million from lower sales volumes, partially offset by higher BGSS prices of $61 million.

Operating Expenses

Energy Costs decreased $155 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance decreased $85 million due to

- a $98 million net reduction related to various clause mechanisms and GPRC, and
- a $13 million decrease in pension and OPEB expenses, net of amounts capitalized,
- partially offset by $10 million of insurance recovery proceeds in 2015,
- a $10 million increase in vegetation management costs, and
- a $6 million net increase due primarily to transmission and distribution corrective maintenance and appliance service costs.

Depreciation and Amortization decreased $327 million due primarily to a $396 million net decrease in amortization of Regulatory Assets, partially offset by an increase in depreciation of $65 million due additional plant placed into service in 2016.

Interest Expense increased $9 million due to increases of

- $14 million due to net debt issuances in 2015, and
- $13 million due to net debt issuances in 2016,
- partially offset by a decreases of $11 million due to the redemption of securitization debt in 2015 and
- $7 million of higher interest related to BGSS in 2015.

Income Tax Expense increased $45 million due primarily to higher pre-tax income partially offset by changes in the reserve for uncertain tax positions and flow through items.

Year Ended December 31, 2015 as compared to 2014

Operating Revenues decreased $130 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $212 million due primarily to an increase in transmission revenues.

- Transmission revenues were $164 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.

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- Electric distribution revenues increased $31 million due primarily to higher sales volumes due to weather.
- Gas distribution revenues increased $17 million due to higher WNC revenues of $35 million due to warmer weather in 2015 compared to 2014, partially offset by $18 million due to lower sales volumes.

Clause Revenues decreased $154 million due to lower STC revenues of $86 million, lower SBC of $31 million, lower MAC of $29 million, and lower SPRC of $8 million. The changes in STC, SBC, MAC and SPRC amounts were entirely offset by decreases in 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, SBC, MAC or SPRC collections.

Commodity Revenues decreased $187 million due to lower Gas revenues, partially offset by higher Electric revenues. This 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 $266 million due to lower BGSS prices of $295 million, partially offset by $29 million from higher sales volumes. The average price of natural gas was 29% lower to the customer in 2015 than in 2014.
- Electric revenues increased $79 million due to $120 million in higher net BGS revenues, comprised of $166 million from higher sales volumes, partially offset by lower prices of $46 million. BGS sales volume increased due primarily to weather. The BGS net revenue increase was partially offset by $41 million in lower revenues from the sale of NUG energy and the collections of NGC due primarily to lower prices.

Operating Expenses

Energy Costs decreased $187 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance increased $2 million, of which the most significant components were increases of

- $33 million in pension and OPEB expenses, net of amounts capitalized,
- $13 million in transmission operating expenses,
- $7 million in gas bad debt expense, and
- a $49 million net increase due to various increases, including information technology expenditures, wages, appliance service costs and preventative maintenance,
- almost entirely offset by a $90 million net reduction related to various clause mechanisms, GPRC and the Capital Infrastructure Program, and
- $10 million of insurance recovery proceeds.

Depreciation and Amortization decreased $14 million due to a $69 million decrease in amortization of Regulatory Assets, partially offset by an increase in depreciation of $55 million due to additional plant in service.

Other Income (Deductions) net increase of $17 million in AFUDC.

Interest Expense increased $3 million due primarily to increases of

- $12 million due to net debt issuances in the latter half of 2014, and
- $9 million due to net debt issuances in 2015,
- partially offset by a decrease of $17 million due to the redemption of securitization debt in 2015.

Income Tax Expense increased $21 million due primarily to higher pre-tax income.

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Power

	Years Ended December 31,			Increase / (Decrease) 2016 vs. 2015		Increase / (Decrease) 2015 vs. 2014	
	2016	2015	2014				
	Millions			Millions	%	Millions	%
Operating Revenues	$4,023	$4,928	$5,434	$(905)	(18)	$(506)	(9)
Energy Costs	1,986	2,150	2,747	(164)	(8)	(597)	(22)
Operation and Maintenance	1,143	1,057	1,186	86	8	(129)	(11)
Depreciation and Amortization	881	291	292	590	N/A	(1)	—
Income from Equity Method Investments	11	14	14	(3)	(21)	—	—
Other Income (Deductions)	45	97	170	(52)	(54)	(73)	(43)
Other-Than-Temporary Impairments	28	53	20	(25)	(47)	33	N/A
Interest Expense	84	121	122	(37)	(31)	(1)	(1)
Income Tax Expense (Benefit)	(61)	511	491	(572)	N/A	20	4

Year Ended December 31, 2016 as compared to 2015

Operating Revenues decreased $905 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $714 million due primarily to

- a decrease of $317 million due to MTM losses in 2016 as compared to MTM gains in 2015. Of this amount, $199 million was due to changes in forward power prices resulting in lower MTM gains this year compared to last year. Also contributing to the decrease was $118 million of higher gains on positions reclassified to realized upon settlement this year compared to last year,
- a decrease of $298 million in energy sales volumes in the PJM, NE and NY regions due primarily to milder weather in 2016 and lower average realized prices,
- a decrease of $80 million in capacity revenue primarily in the PJM region due to the retirement of older peaking units in June 2015, and
- a decrease of $49 million due to lower operating reserve revenues in the PJM region due to less congestion and lower prices,
- partially offset by a net increase of $19 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions, partially offset by lower average prices, and
- a net increase of $8 million due to new solar projects beginning commercial operations.

Gas Supply Revenues decreased $191 million due primarily to

- a decrease of $183 million in sales under the BGSS contract due primarily to lower average sales prices and a decrease in sales volumes due to warmer average temperatures in the 2016 heating season, and
- a decrease of $9 million due to MTM losses in 2016 due to changes in forward prices.

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 $164 million due to

Generation costs decreased $95 million due primarily to

- lower fuel costs of $288 million reflecting lower average realized prices for natural gas and the utilization of lower volumes of fuel,
- partially offset by a net increase of $143 million primarily due to realized gains on FTRs in PJM in the prior year due to extremely cold weather, and

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- a $62 million charge associated with the announced early retirement of the Mercer and Hudson units, primarily related to a coal inventory write-down.

Gas costs decreased $69 million due to

- a decrease of $101 million related to sales under the BGSS contract due primarily to lower average gas costs and a decrease in volumes sold due to warmer average temperatures during the 2016 winter heating season,
- partially offset by an increase of $32 million related to sales to third parties due primarily to higher average gas costs and an increase in volumes sold.

Operation and Maintenance increased $86 million due to

- $145 million of insurance recoveries received in 2015 related to Superstorm Sandy, and
- $53 million of charges related to the early retirement of the Hudson and Mercer units,
- partially offset by a net decrease of $73 million related to our fossil plants, largely due to higher costs incurred in 2015 for our planned major outages at the Bethlehem Energy Center and Bergen generating plants,
- a net decrease of $31 million related to our nuclear plants due primarily to lower planned outage costs at our 100%-owned Hope Creek plant and our 57%-owned Salem Unit 1 plant, and
- an $8 million decrease due to lower pension and OPEB costs.

Depreciation and Amortization increased $590 million due primarily to

- $555 million of accelerated depreciation due to the early retirement of the Hudson and Mercer units,
- a $24 million increase due primarily to a higher nuclear asset base, and
- $5 million of higher depreciation due to new solar projects.

Other Income (Deductions) decreased $52 million due primarily to $28 million of insurance recoveries received in 2015 related to Superstorm Sandy and $38 million of lower net realized gains from the NDT Fund in 2016, partially offset by $10 million of lower purchased tax credits in 2016.

Other-Than-Temporary Impairments decreased $25 million due to lower impairments of equity securities in the NDT Fund in 2016.

Interest Expense decreased $37 million due to

- $27 million of interest capitalized for the construction of three new fossil stations: Bridgeport Harbor 5, Sewaren 7 and Keys Energy Center, and
- a $15 million decrease due to the maturity of 5.50% of Senior Notes in December 2015,
- partially offset by an increase of $5 million due to net debt issuances in 2016.

Income Tax Expense decreased $572 million in 2016 due primarily to a pre-tax loss in 2016 as compared to pre-tax income in 2015.

Year Ended December 31, 2015 as compared to 2014

Operating Revenues decreased $506 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $172 million due to

- a decrease of $192 million due primarily to lower capacity revenues resulting from lower average auction prices and the retirement of older peaking units in June 2015, coupled with lower ancillary and operating reserve revenues in the PJM region, and

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- lower net revenues of $73 million due primarily to lower energy volumes sold in the NE region and lower average realized prices in the NE and NY regions, partially offset by higher energy volumes sold in the NY and PJM regions. Also included in the net decrease is $22 million due to lower MTM gains in 2015.
- partially offset by an increase of $56 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions coupled with higher average prices in the NE region, and
- an increase of $37 million due primarily to higher volumes of electricity sold under the BGS contract at higher average prices.

Gas Supply Revenues decreased $336 million due to

- a net decrease of $214 million in sales under the BGSS contract, substantially comprised of lower average sales prices, and
- a decrease of $122 million on sales to third-party customers, of which $93 million was due to lower average sales prices and $29 million to lower volumes sold.

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 $597 million due to

- Generation costs decreased $254 million due primarily to lower fuel costs of $330 million reflecting lower average realized natural gas and coal prices and the utilization of lower volumes of oil and coal. MTM gains in 2015 as compared to MTM losses in 2014 resulted in a $66 million decrease. These decreased costs were partially offset by higher congestion costs in the PJM region of $140 million.
- Gas costs decreased $343 million mainly related to a decrease in average gas costs on both obligations under the BGSS contract and sales to third parties.

Operation and Maintenance decreased $129 million due primarily to

- a decrease of $145 million due to insurance recoveries received in 2015 related to Superstorm Sandy, and
- a net decrease of $61 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 BEC generating plant and installation of upgraded technology at our combined cycle Bergen plant,
- partially offset by an increase of $51 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 $30 million increase due to higher pension and OPEB costs, net of amounts capitalized.

Other Income (Deductions) decreased $73 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 $33 million due primarily to an increase in impairments of equity securities in the NDT Fund.

Income Tax Expense increased $20 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.

Financing Methodology

We expect our capital requirements to be met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt for capital investments.

PSE&G's sources of external liquidity include a $600 million multi-year syndicated credit facility. PSE&G uses internally generated cash flow and its commercial paper program to meet seasonal, intra-month and temporary working capital needs.

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PSE&G does not engage in any intercompany borrowing or lending arrangements. PSE&G maintains back-up facilities in an amount sufficient to cover the commercial paper and letters of credit outstanding. PSE&G's dividend payments to/capital contributions from PSEG are consistent with its capital structure objectives which have been established to maintain investment grade credit ratings. PSE&G's long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings, PSEG LI and Services participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Servco does not participate in the corporate money pool. Servco's short-term liquidity needs are met through an account funded and owned by LIPA.

PSEG's sources of external liquidity may include the issuance of long-term debt securities and the incurrence of additional indebtedness under credit facilities. Our current sources of external liquidity include multi-year syndicated credit facilities totaling $1 billion. These facilities are available to back-stop PSEG's commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG's credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. PSEG also has a $500 million term loan credit agreement that is scheduled to expire in November 2017. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.6 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Credit capacity is primarily used to provide collateral in support of Power's forward energy sale and forward fuel purchase contracts as the market prices for energy and fuel fluctuate, and to meet potential collateral postings in the event that Power is downgraded to below investment grade by S&P or Moody's. Power's dividend payments to PSEG are also designed to be consistent with its capital structure objectives which have been established to maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2016, our operating cash flow decreased by $608 million. For the year ended December 31, 2015, our operating cash flow increased by $759 million. The net changes were primarily due to net changes from our subsidiaries as discussed below.

PSE&G

PSE&G's operating cash flow decreased $231 million from $2,125 million to $1,894 million for the year ended December 31, 2016, as compared to 2015, due primarily to a decrease from lower collections for securitization debt principal repayments which were $259 million in 2015, a decrease of $249 million in cash receipts from customers due to lower sales driven by warmer winter weather in 2016 compared to 2015, a decrease of $90 million related to a change in regulatory deferrals, primarily driven by net returns to customers in 2016 related to 2015 overcollections, partially offset by higher bill credits and $74 million in increased vendor payments. These amounts were partially offset by higher earnings and higher tax refunds in 2016.

PSE&G's operating cash flow increased $292 million from $1,833 million to $2,125 million for the year ended December 31, 2015, as compared to 2014, due primarily to higher earnings, a $311 million reduction in tax payments, and an increase of $102 million due to higher customer billings in the fourth quarter of 2014 primarily as a result of increased usage due to weather. These increases were partially offset by a decrease of $250 million related to a change in regulatory deferrals, primarily driven by the return of prior year overcollections to customers for BGSS gas costs, Gas WNC charges and BGS costs.

Power

Power's operating cash flow decreased $451 million from $1,706 million to $1,255 million for the year ended December 31, 2016, as compared to 2015, primarily resulting from lower earnings, an increase in margin deposit requirements of $198 million, and a $134 million decrease from net collection of counterparty receivables, partially offset by a reduction in tax payments.

Power's operating cash flow increased $281 million from $1,425 million to $1,706 million for the year ended December 31, 2015, as compared to 2014, primarily resulting from higher earnings, a decrease in margin deposit requirements of $144 million, and a $78 million increase from net collection of counterparty receivables. These amounts were partially offset by an increase of $325 million in tax payments.

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Short-Term Liquidity
We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2016 were as follows:

Company/Facility	As of December 31, 2016		
	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$1,000	$ 398	$ 602
PSE&G	600	14	586
Power	2,553	198	2,355
Total	$4,153	$ 610	$ 3,543

As of December 31, 2016, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating from S&P or Moody's, which would represent a three level downgrade from its current S&P or Moody's ratings. In the event of a deterioration of Power's credit rating certain of Power's agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $783 million and $864 million as of December 31, 2016 and 2015, respectively. The early retirement of Power's Hudson and Mercer coal/gas generation units is not expected to have a material impact on Power's debt covenant ratios or its ability to obtain credit facilities. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements.
For additional information, see Item 8.Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.
Long-Term Debt Financing
PSEG has a floating rate $500 million term loan maturing in November 2017.
For a discussion of our long-term debt transactions during 2016 and into 2017, see Item 8. Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.
Debt Covenants
Our credit agreements contain maximum debt to equity ratios and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.
In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2016, PSE&G's Mortgage coverage ratio was 4.2 to 1 and the Mortgage would permit up to approximately $5.7 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.
Default Provisions
Our bank credit agreements and indentures contain various, customary default provisions that could result in the potential acceleration of indebtedness under the defaulting company's agreement.
In particular, PSEG's bank credit agreements contain provisions under which certain events, including an acceleration of material indebtedness under PSE&G's and Power's respective financing agreements, a failure by PSE&G or Power

to satisfy certain final judgments and certain bankruptcy events by PSE&G or Power, that would constitute an event of default under the PSEG bank credit agreements. Under the PSEG bank credit agreements, it would also be an event of default if either PSE&G or Power ceases to be wholly owned by PSEG. The PSE&G and Power bank credit agreements include similar default provisions; however such provisions only relate to the respective borrower under such agreement and its subsidiaries and do not contain cross default provisions to each other. The PSE&G and Power bank credit agreements do not include cross default provisions relating to PSEG.

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There are no cross acceleration provisions in PSEG's or PSE&G's indentures. However, PSEG's existing notes include a cross acceleration provision that may be triggered upon the acceleration of more than $75 million of indebtedness incurred by PSEG. Such provision does not extend to an acceleration of indebtedness by any of PSEG's subsidiaries. Power's indenture includes a cross acceleration provision similar to that described above for PSEG's existing notes except that such provision may be triggered upon the acceleration of more than $50 million of indebtedness incurred by Power or any of its subsidiaries. Such provision does not cross accelerate to PSEG, any of PSEG's subsidiaries (other than Power and its subsidiaries), PSE&G or any of PSE&G's subsidiaries.

Ratings Triggers

Our debt indentures and credit agreements do not contain any material 'ratings triggers' that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.

In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.

Fluctuations in commodity prices or a deterioration of Power's credit rating to below investment grade could increase Power's required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade to below investment grade by S&P or Moody's at today's market prices.

Common Stock Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	2016	2015	2014
Per Share	$1.64	$1.56	$1.48
in Millions	$830	$789	$748

On February 21, 2017, our Board of Directors approved a $0.43 per share common stock dividend for the first quarter of 2017. This reflects an indicative annual dividend rate of $1.72 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 8. Financial Statements and Supplementary Data—Note 22. 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 January 2016, S&P published updated research reports on PSEG and PSE&G and the existing ratings and outlooks were unchanged. In June 2016, Moody's published credit opinions on Power and PSE&G and the existing ratings and outlooks were unchanged. In June 2016, S&P published an updated research report on Power and the existing rating and outlook were unchanged. In September 2016, Moody's published an updated research report on PSEG and the existing rating and outlook were unchanged.

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	Moody’s (A)	S&P (B)
PSEG		
Outlook	Positive	Stable
Senior Notes	Baa2	BBB
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.

Other Comprehensive Income

For the year ended December 31, 2016, we had Other Comprehensive Income of $32 million on a consolidated basis. Other Comprehensive Income was due primarily to a $42 million increase in net unrealized gains related to Available-for-Sale Securities and $2 million of unrealized gains on derivative contracts accounted for as hedges, partially offset by a decrease of $12 million in our consolidated liability for pension and postretirement benefits. See Item 8. Financial Statements and Supplementary Data—Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

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CAPITAL REQUIREMENTS

We expect that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These projections include Allowance for Funds Used During Construction and Interest Capitalized During Construction for PSE&G and Power, respectively. These amounts are subject to change, based on various factors. Amounts shown below for Energy Strong, GSMP and Solar/Energy Efficiency programs are for currently approved programs. We intend to continue to invest in infrastructure modernization and will seek to extend these and related programs as appropriate. We will also continue to approach potential growth investments for Power opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2017	2018	2019
		Millions	
PSE&G:			
Transmission	$1,630	$ 1,375	$1,110
Distribution	1,180	775	615
Energy Strong	205	75	15
Gas System Modernization Program	305	315	50
Solar/Energy Efficiency	90	75	60
Total PSE&G	$3,410	$ 2,615	$1,850
Power:			
Baseline	$190	$ 210	$170
Environmental/Regulatory	35	35	35
Fossil Growth Opportunities	825	405	90
Nuclear Expansion	20	20	10
Solar Growth Opportunities	130	—	—
Total Power	$1,200	$ 670	$305
Other	$50	$ 35	$35
Total PSEG	$4,660	$ 3,320	$2,190

PSE&G

PSE&G’s projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G’s projected expenditures for the various items reported above are primarily comprised of the following:

- Transmission—investments focused on reliability improvements and replacement of aging infrastructure.
- Distribution—investments for new business, reliability improvements, and replacement of equipment that has reached the end of its useful life.
- Energy Strong—Electric and Gas Distribution reliability investment program focused on system hardening and resiliency.
- Gas System Modernization Program—Gas Distribution investment program to replace aging infrastructure.
- Solar/Energy Efficiency—investments associated with grid-connected solar, solar loan programs, and customer energy efficiency programs.

In August 2016, PSE&G filed a petition with the BPU requesting approval of the $268 million investment and an associated cost recovery mechanism to develop a project where PSE&G would rebuild New Jersey Transit’s Mason substation and related facilities in Kearny, NJ. This is not included in PSE&G’s projected capital expenditures.

In 2016, PSE&G made $2,816 million of capital expenditures, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $131 million, which are included in operating cash flows.

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Power

Power’s projected expenditures for the various items listed above are primarily comprised of the following:

- Baseline—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Fossil Growth Opportunities—investments associated with new construction, including Keys Energy Center, Sewaren 7 and BH5, and with upgrades to increase efficiency and output at combined cycle plants.
- Nuclear Expansion—investments associated with certain nuclear capital projects, primarily at existing facilities designed to increase operating output.
- Solar Growth Opportunities—investments associated with the construction of utility-scale photovoltaic facilities.

In 2016, Power made $1,136 million of capital expenditures, excluding $207 million for nuclear fuel, primarily related to various projects at Fossil, Solar and Nuclear.

Disclosures about Contractual Obligations

The following table reflects our contractual cash obligations in the respective periods in which they are due. In addition, the table summarizes anticipated debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 14. Debt and Credit Facilities.

The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information.

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	Total Amount Committed Millions	Less Than 1 Year	2 - 3 Years	4- 5 Years	Over 5 Years
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
PSEG	$1,200	$500	$400	$300	$—
PSE&G	7,883	—	1,250	693	5,940
Power	2,400	—	294	1,356	750
Interest on Recourse Debt					
PSEG	57	20	25	12	—
PSE&G	4,986	299	555	502	3,630
Power	935	113	221	170	431
Capital Lease Obligations					
Power	3	1	1	1	—
Operating Leases					
PSE&G	100	12	15	12	61
Power	52	3	6	4	39
Services	198	13	26	27	132
Other	5	1	2	2	—
Energy-Related Purchase Commitments					
Power	2,625	745	898	450	532
Total Contractual Cash Obligations	$20,444	$1,707	$3,693	$3,529	$11,515
Liability Payments for Uncertain Tax Positions					
PSEG	$14	$14	$—	$—	$—
PSE&G	3	3	—	—	—
Power	7	7	—	—	—

OFF-BALANCE SHEET ARRANGEMENTS

PSEG and Power issue guarantees, primarily in conjunction with certain of Power’s energy contracts. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for further discussion.

Through Energy Holdings, we have investments in leveraged leases that are accounted for in accordance with GAAP Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease arrangement, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and is not presented on our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secures the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operations. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments and Note 8. Financing Receivables.

In the event that collection of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would consider the need to record an impairment of its investment. In the event the lease is ultimately rejected by the lessee in a Bankruptcy Court proceeding, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate

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can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

PSEG sponsors qualified and nonqualified pension plans covering PSEG’s and its participating affiliates’ current and former employees who meet certain eligibility criteria. The market-related value of plan assets held for the qualified pension plan is equal to the fair value of these assets as of year-end. The plan assets are comprised of investments in both debt and equity securities which are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. We calculate pension costs using various economic and demographic assumptions.

Assumptions and Approach Used: Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns.

Assumption	2016	2015	2014
Discount Rate	4.29 %	4.54 %	4.20 %
Expected Rate of Return on Plan Assets	8.00 %	8.00 %	8.00 %

The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate is determined by developing a spot rate curve based on the yield to maturity of a universe of high quality corporate bonds with similar maturities to the plan obligations. The spot rates are used to discount the estimated plan distributions. The discount rate is the single equivalent rate that produces the same result as the full spot rate curve.

At the end of 2015, we changed the approach used to measure future service and interest costs for pension benefits. See Item 8. Financial Statements and Supplementary Data—Note 12. Pension and Other Postretirement Benefits (OPEB) and Savings Plans for additional information.

Our expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class, long-term inflation assumptions and a premium for active management.

Based on the above assumptions, we have estimated net periodic pension expense in 2017 of approximately $3 million or $6 million, net of amounts capitalized.

We utilize a corridor approach that reduces the volatility of reported pension expense/income. The corridor requires differences between actuarial assumptions and plan results be deferred and amortized as part of expense/income. This occurs only when the accumulated differences exceed 10% of the greater of the pension benefit obligation or the fair value of plan assets as of each year-end. The excess would be amortized over the average remaining service period of the active employees, which is approximately thirteen years.

As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans’ assets. As a result, we estimate that in 2017, the total net periodic benefit costs are expected to decrease by approximately $72 million or $48 million, net of amounts capitalized, as compared to the 2017 amounts that would have been recognized had the plans not been merged. This is due to the amortization period for gains and losses for the merged plan resulting in lower amortization than that of the individual plans. No changes were made to the benefit formulas, vesting provisions, or to the employees covered by the plans.

Effect if Different Assumptions Used: As part of the business planning process, we have modeled future costs assuming a 7.80% expected rate of return and a 4.29% discount rate for 2017. Actual future pension expense/income and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

The following chart reflects the sensitivities associated with a change in certain assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

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Assumption	% Change	Impact on Pension Benefit Obligation as of December 31, 2016	Increase to Pension Expense in 2017	Increase to Pension Expense, net of Amounts Capitalized in 2017
		Millions		
Discount Rate	(1)%	$ 737	$ 40	$ 27
Expected Rate of Return on Plan Assets	(1)%	N/A	$ 50	$ 33

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Derivative Instruments

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 executing derivative transactions. Derivative instruments are used 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.

Current accounting guidance requires us to recognize all derivatives on the balance sheet at their fair value, except for derivatives that qualify for and are designated as normal purchases and normal sales contracts.

Assumptions and Approach Used: In general, the fair value of our derivative instruments is determined primarily by end of day clearing market prices from an exchange, such as NYMEX, Intercontinental Exchange and Nodal Exchange, or auction prices. Fair values of other energy contracts may be based on broker quotes.

For a small number of contracts where limited observable inputs or pricing information are available, modeling techniques are employed in determination of their fair value using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable.

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for, or are not designated as, either cash flow or fair value hedge accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

Effect if Different Assumptions Used: Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded in our Consolidated Statements of Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data – Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies, Note 16. Financial Risk Management Activities and Note 17. Fair Value Measurements.

Long-Lived Assets

Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset’s or asset group’s carrying amount may not be recoverable.

Assumptions and Approach Used: In the event certain triggers exist indicating an asset/asset group may not be recoverable, an undiscounted cash flow test is performed to determine if an impairment exists. When the carrying value of a long-lived asset/asset group exceeds the undiscounted estimate of future cash flows associated with the asset/asset group, an impairment may exist to the extent that the fair value of the asset/asset group is less than its carrying amount. These tests require significant estimates and judgment when developing expected future cash flows. Significant inputs include forward power prices, fuel costs, dispatch rates, other operating and capital expenditures and the cost of borrowing.

Effect if Different Assumptions Used: The above cash flow tests and fair value estimates may be impacted by a change in the assumptions noted above and could significantly impact the outcome, triggering additional impairment tests or write-offs.

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Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data – Note 7. Long-Term Investments and Note 8. Financing Receivables.

Assumptions and Approach Used: Residual values are the estimated values of the leased assets at the end of the respective lease terms. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses,
- discount rates, and
- the current estimated economic viability of the plants after the end of the base lease term.

Residual valuations are performed at least annually for each plant subject to lease using specific assumptions tailored to each plant. Those valuations are compared to the recorded residual values to determine if an impairment is warranted.

Effect if Different Assumptions Used: A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market's view of long-term power prices, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $91 million.

Asset Retirement Obligations (ARO)

PSE&G, Power and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result of timing differences between the recording of costs and costs recovered through the rate-making process. We accrete the ARO liability to reflect the passage of time.

Assumptions and Approach Used: Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

- estimation of dates for retirement, which can be dependent on environmental and other legislation,
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities,
- discount rates,
- cost escalation rates,
- market risk premium,
- inflation rates, and
- if applicable, past experience with government regulators regarding similar obligations.

We obtain updated cost studies triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

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Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power's nuclear facilities comprised 89% of Power's total AROs as of December 31, 2016. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

- license renewals,
- early shutdown,
- safe storage for a period of time after retirement, and
- recovery from the federal government of costs incurred for spent nuclear fuel.

Effect if Different Assumptions Used: Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a decrease of 1% in the discount rate would result in a $39 million increase in the Nuclear ARO as of December 31, 2016. An increase of 1% in the inflation rate would result in a $203 million increase in the Nuclear ARO as of December 31, 2016. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $283 million at December 31, 2016.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

Assumptions and Approach Used: PSE&G recognizes Regulatory Assets where it is probable that such costs will be recoverable in future rates from customers and Regulatory Liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G's regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a Regulatory Asset or Liability:

- past experience regarding similar items with the BPU,
- treatment of a similar item in an order by the BPU for another utility,
- passage of new legislation, and
- recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. When the recovery of a Regulatory Asset or payment of a Regulatory Liability is no longer probable, PSE&G charges or credits earnings, as appropriate.

Effect if Different Assumptions Used: A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

ITEM 7A. 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 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.

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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. 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.

	MTM VaR Millions			
Years Ended December 31,	2016		2015	
95% Confidence Level, Loss could exceed VaR one day in 20 days				
Period End	$	26	$	24
Average for the Period	$	16	$	17
High	$	32	$	40
Low	$	10	$	8
99.5% Confidence Level, Loss could exceed VaR one day in 200 days				
Period End	$	40	$	38
Average for the Period	$	25	$	26
High	$	51	$	63
Low	$	16	$	12

See Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities for a discussion of credit risk.
Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2016, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $366 million decrease in the fair value of debt, including a $303 million decrease at PSE&G and a $57 million decrease at Power.

Debt and Equity Securities

We have $5.6 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,

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- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and
- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Fund is comprised primarily of fixed income and equity securities. As of December 31, 2016, the portfolio included $957 million of equity securities and $857 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2016, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $96 million.

We use duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Fund currently has a duration of 5.89 years and a yield of 2.61%. The portfolio’s value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2016, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $50 million.

Credit Risk

See Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power’s and PSE&G’s credit risk.

Energy Holdings has credit risk related to its investments in leases, which totaled $(25) million, net of deferred taxes of $674 million, as of December 31, 2016. These leveraged leases are concentrated in the U.S. energy industry. See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables for counterparties’ credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets. In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings’ portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, PSE&G and 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 as to any other company.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(a). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Sole Stockholder of
Public Service Electric and Gas Company
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Sole Member of
PSEG Power LLC
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the “Company”) as of December 31, 2016 and 2015, and the related consolidated statements of operations, comprehensive income, member’s equity, and cash flows for each of the three years in the period ended December 31, 2016. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company’s management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2017

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data

	Years Ended December 31,		
	2016	2015	2014
OPERATING REVENUES	$9,061	$10,415	$10,886
OPERATING EXPENSES			
Energy Costs	3,001	3,261	3,886
Operation and Maintenance	3,008	2,978	3,150
Depreciation and Amortization	1,476	1,214	1,227
Total Operating Expenses	7,485	7,453	8,263
OPERATING INCOME	1,576	2,962	2,623
Income from Equity Method Investments	11	12	13
Other Income	191	254	290
Other Deductions	(67)	(102)	(61)
Other-Than-Temporary Impairments	(28)	(53)	(20)
Interest Expense	(385)	(393)	(389)
INCOME BEFORE INCOME TAXES	1,298	2,680	2,456
Income Tax Expense	(411)	(1,001)	(938)
NET INCOME	$887	$1,679	$1,518
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	505	505	506
DILUTED	508	508	508
NET INCOME PER SHARE:			
BASIC	$1.76	$3.32	$3.00
DILUTED	$1.75	$3.30	$2.99

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2016	2015	2014
NET INCOME	$887	$1,679	$1,518
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(41), $34, and $26 for the years ended 2016, 2015 and 2014, respectively	42	(27)	(27)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $(1), $7 and $(8) for the years ended 2016, 2015 and 2014, respectively	2	(10)	12
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $8, $(18) and $120 for the years ended 2016, 2015 and 2014, respectively	(12)	25	(173)
Other Comprehensive Income (Loss), net of tax	32	(12)	(188)
COMPREHENSIVE INCOME	$919	$1,667	$1,330

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$423	$394
Accounts Receivable, net of allowances of $68 in 2016 and $67 in 2015	1,161	1,068
Tax Receivable	78	305
Unbilled Revenues	260	197
Fuel	326	463
Materials and Supplies, net	561	513
Prepayments	76	135
Derivative Contracts	163	242
Regulatory Assets	199	164
Other	7	13
Total Current Assets	3,254	3,494
PROPERTY, PLANT AND EQUIPMENT	39,337	35,494
Less: Accumulated Depreciation and Amortization	(10,051)	(8,955)
Net Property, Plant and Equipment	29,286	26,539
NONCURRENT ASSETS		
Regulatory Assets	3,319	3,196
Long-Term Investments	1,050	1,233
Nuclear Decommissioning Trust (NDT) Fund	1,859	1,754
Long-Term Tax Receivable	104	171
Long-Term Receivable of VIEs	589	495
Other Special Funds	217	227
Goodwill	16	16
Other Intangibles	98	102
Derivative Contracts	24	77
Other	254	231
Total Noncurrent Assets	7,530	7,502
TOTAL ASSETS	$40,070	$37,535

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2016	2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$500	$734
Commercial Paper and Loans	388	364
Accounts Payable	1,459	1,369
Derivative Contracts	13	76
Accrued Interest	97	96
Accrued Taxes	31	42
Clean Energy Program	142	142
Obligation to Return Cash Collateral	132	128
Regulatory Liabilities	88	123
Regulatory Liabilities of VIEs	—	42
Other	426	459
Total Current Liabilities	3,276	3,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,658	8,166
Regulatory Liabilities	118	175
Asset Retirement Obligations	726	679
Other Postretirement Benefit (OPEB) Costs	1,324	1,228
OPEB Costs of Servco	452	375
Accrued Pension Costs	568	487
Accrued Pension Costs of Servco	128	114
Environmental Costs	401	415
Derivative Contracts	3	27
Long-Term Accrued Taxes	180	212
Other	211	181
Total Noncurrent Liabilities	12,769	12,059
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT	10,895	8,834
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2016 and 2015— 534 shares	4,936	4,915
Treasury Stock, at cost, 2016—29 shares; 2015—28 shares	(717)	(671)
Retained Earnings	9,174	9,117
Accumulated Other Comprehensive Loss	(263)	(295)
Total Common Stockholders' Equity	13,130	13,066
Noncontrolling Interest	—	1
Total Stockholders' Equity	13,130	13,067
Total Capitalization	24,025	21,901
TOTAL LIABILITIES AND CAPITALIZATION	$40,070	$37,535

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$887	$1,679	$1,518
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,476	1,214	1,227
Amortization of Nuclear Fuel	203	213	200
Renewable Energy Credit (REC) Compliance Accrual	109	104	69
Impairment Costs for Early Plant Retirements	102	—	—
Provision for Deferred Income Taxes (Other than Leases) and ITC	474	685	515
Non-Cash Employee Benefit Plan Costs	127	161	47
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(6)	26	(4)
Net (Gain) Loss on Lease Investments	92	—	(3)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	183	(143)	(93)
Net Change in Regulatory Assets and Liabilities	(138)	(48)	187
Cost of Removal	(131)	(120)	(98)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(26)	(38)	(166)
Net Change in Certain Current Assets and Liabilities			
Tax Receivable	303	(94)	30
Accrued Taxes	3	(91)	(156)
Margin Deposit	(76)	122	(22)
Other Current Assets and Liabilities	(180)	288	(31)
Employee Benefit Plan Funding and Related Payments	(103)	(109)	(95)
Other	12	70	35
Net Cash Provided By (Used In) Operating Activities	3,311	3,919	3,160
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(4,199)	(3,863)	(2,820)
Purchase of Emissions Allowances and RECs	(99)	(106)	(101)
Proceeds from Sale of Capital Leases and Investments	—	14	25
Proceeds from Sales of Available-for-Sale Securities	824	1,501	1,915
Investments in Available-for-Sale Securities	(856)	(1,552)	(1,934)
Other	82	64	23
Net Cash Provided By (Used In) Investing Activities	(4,248)	(3,942)	(2,892)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	24	364	(60)
Issuance of Long-Term Debt	2,675	1,350	1,250
Redemption of Long-Term Debt	(824)	(600)	(500)
Redemption of Securitization Debt	—	(259)	(237)
Cash Dividend Paid on Common Stock	(830)	(789)	(748)
Other	(79)	(51)	(64)
Net Cash Provided By (Used In) Financing Activities	966	15	(359)
Net Increase (Decrease) in Cash and Cash Equivalents	29	(8)	(91)
Cash and Cash Equivalents at Beginning of Period	394	402	493

Cash and Cash Equivalents at End of Period	$423	$394	$402
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$(245)	$447	$538
Interest Paid, Net of Amounts Capitalized	$365	$381	$382
Accrued Property, Plant and Equipment Expenditures	$664	$510	$382

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Millions

	Common Stock Shs.	Common Stock Amount	Treasury Stock Shs.	Treasury Stock Amount	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance as of January 1, 2014	534	$4,861	(28)	$(615)	$7,457	$ (95)	$ 1	$11,609
Net Income	—	—	—	—	1,518	—	—	1,518
Other Comprehensive Income (Loss), net of tax (expense) benefit of $138	—	—	—	—	—	(188)	—	(188)
Comprehensive Income								1,330
Cash Dividends on Common Stock	—	—	—	—	(748)	—	—	(748)
Other	—	15	—	(20)	—	—	—	(5)
Balance as of December 31, 2014	534	$4,876	(28)	$(635)	$8,227	$ (283)	$ 1	$12,186
Net Income	—	—	—	—	1,679	—	—	1,679
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	—	—	(12)	—	(12)
Comprehensive Income								1,667
Cash Dividends on Common Stock	—	—	—	—	(789)	—	—	(789)
Other	—	39	—	(36)	—	—	—	3
Balance as of December 31, 2015	534	$4,915	(28)	$(671)	$9,117	$ (295)	$ 1	$13,067
Net Income	—	—	—	—	887	—	—	887
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(34)	—	—	—	—	—	32	—	32
Comprehensive Income								919
Cash Dividends on Common Stock	—	—	—	—	(830)	—	—	(830)
Other	—	21	(1)	(46)	—	—	(1)	(26)
Balance as of December 31, 2016	534	$4,936	(29)	$(717)	$9,174	$ (263)	$ —	$13,130

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2016	2015	2014
OPERATING REVENUES	$6,221	$6,636	$6,766
OPERATING EXPENSES			
Energy Costs	2,567	2,722	2,909
Operation and Maintenance	1,475	1,560	1,558
Depreciation and Amortization	565	892	906
Total Operating Expenses	4,607	5,174	5,373
OPERATING INCOME	1,614	1,462	1,393
Other Income	83	79	61
Other Deductions	(4)	(4)	(3)
Interest Expense	(289)	(280)	(277)
INCOME BEFORE INCOME TAXES	1,404	1,257	1,174
Income Tax Expense	(515)	(470)	(449)
NET INCOME	$889	$787	$725

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2016	2015	2014
NET INCOME	$889	$787	$725
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0 and $0 for the years ended 2016, 2015 and 2014, respectively	—	(1)	1
COMPREHENSIVE INCOME	$889	$786	$726

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$390	$198
Accounts Receivable, net of allowances of $68 in 2016 and $67 in 2015	810	787
Accounts Receivable-Affiliated Companies	76	222
Unbilled Revenues	260	197
Materials and Supplies	180	148
Prepayments	9	31
Regulatory Assets	199	164
Derivative Contracts	—	13
Other	6	9
Total Current Assets	1,930	1,769
PROPERTY, PLANT AND EQUIPMENT	26,347	23,732
Less: Accumulated Depreciation and Amortization	(5,760)	(5,504)
Net Property, Plant and Equipment	20,587	18,228
NONCURRENT ASSETS		
Regulatory Assets	3,319	3,196
Long-Term Investments	299	330
Other Special Funds	43	49
Other	110	105
Total Noncurrent Assets	3,771	3,680
TOTAL ASSETS	$26,288	$23,677

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2016	2015
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$—	$171
Commercial Paper and Loans	—	153
Accounts Payable	718	724
Accounts Payable—Affiliated Companies	260	292
Accrued Interest	76	70
Clean Energy Program	142	142
Derivative Contracts	5	—
Obligation to Return Cash Collateral	132	128
Regulatory Liabilities	88	123
Regulatory Liabilities of VIEs	—	42
Other	296	297
Total Current Liabilities	1,717	2,142
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	5,873	5,181
OPEB Costs	1,009	937
Accrued Pension Costs	250	202
Regulatory Liabilities	118	175
Environmental Costs	332	365
Asset Retirement Obligations	213	218
Derivative Contracts	—	11
Long-Term Accrued Taxes	130	109
Other	116	114
Total Noncurrent Liabilities	8,041	7,312
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT	7,818	6,650
STOCKHOLDER’S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2016 and 2015—132 shares	892	892
Contributed Capital	945	695
Basis Adjustment	986	986
Retained Earnings	5,888	4,999
Accumulated Other Comprehensive Income	1	1
Total Stockholder’s Equity	8,712	7,573
Total Capitalization	16,530	14,223
TOTAL LIABILITIES AND CAPITALIZATION	$26,288	$23,677

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$889	$787	$725
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	565	892	906
Provision for Deferred Income Taxes and ITC	658	386	310
Non-Cash Employee Benefit Plan Costs	72	95	27
Cost of Removal	(131)	(120)	(98)
Net Change in Other Regulatory Assets and Liabilities	(138)	(48)	187
Net Change in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	(84)	165	63
Materials and Supplies	(7)	(15)	(18)
Prepayments	22	11	(18)
Accounts Payable	(29)	45	(3)
Accounts Receivable/Payable-Affiliated Companies, net	199	—	(167)
Other Current Assets and Liabilities	8	(29)	6
Employee Benefit Plan Funding and Related Payments	(82)	(91)	(83)
Other	(48)	47	(4)
Net Cash Provided By (Used In) Operating Activities	1,894	2,125	1,833
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,816)	(2,692)	(2,164)
Proceeds from Sales of Available-for-Sale Securities	22	21	103
Investments in Available-for-Sale Securities	(24)	(22)	(101)
Solar Loan Investments	14	11	7
Other	15	11	—
Net Cash Provided By (Used In) Investing Activities	(2,789)	(2,671)	(2,155)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	(153)	153	(60)
Issuance of Long-Term Debt	1,275	850	1,250
Redemption of Long-Term Debt	(271)	(300)	(500)
Redemption of Securitization Debt	—	(259)	(237)
Contributed Capital	250	—	175
Other	(14)	(10)	(14)
Net Cash Provided By (Used In) Financing Activities	1,087	434	614
Net Increase (Decrease) in Cash and Cash Equivalents	192	(112)	292
Cash and Cash Equivalents at Beginning of Period	198	310	18
Cash and Cash Equivalents at End of Period	$390	$198	$310
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$(295)	$(28)	$283
Interest Paid, Net of Amounts Capitalized	$273	$261	$259
Accrued Property, Plant and Equipment Expenditures	$420	$396	$292

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
Millions

	Common Stock	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2014	$ 892	$ 520	$ 986	$ 3,487	$ 1	$ 5,886
Net Income	—	—	—	725	—	725
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	1	1
Comprehensive Income						726
Contributed Capital		175	—	—	—	175
Balance as of December 31, 2014	$ 892	$ 695	$ 986	$ 4,212	$ 2	$ 6,787
Net Income	—	—	—	787	—	787
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	(1)	(1)
Comprehensive Income						786
Balance as of December 31, 2015	$ 892	$ 695	$ 986	$ 4,999	$ 1	$ 7,573
Net Income	—	—	—	889	—	889
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	—	—
Comprehensive Income						889
Contributed Capital	—	250	—	—	—	250
Balance as of December 31, 2016	$ 892	$ 945	$ 986	$ 5,888	$ 1	$ 8,712

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2016	2015	2014
OPERATING REVENUES	$4,023	$4,928	$5,434
OPERATING EXPENSES			
Energy Costs	1,986	2,150	2,747
Operation and Maintenance	1,143	1,057	1,186
Depreciation and Amortization	881	291	292
Total Operating Expenses	4,010	3,498	4,225
OPERATING INCOME	13	1,430	1,209
Income from Equity Method Investments	11	14	14
Other Income	102	169	222
Other Deductions	(57)	(72)	(52)
Other-Than-Temporary Impairments	(28)	(53)	(20)
Interest Expense	(84)	(121)	(122)
INCOME (LOSS) BEFORE INCOME TAXES	(43)	1,367	1,251
Income Tax Benefit (Expense)	61	(511)	(491)
NET INCOME	$18	$856	$760

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2016	2015	2014
NET INCOME	$18	$856	$760
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(41), $32, and $28 for the years ended 2016, 2015 and 2014, respectively	42	(25)	(30)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $7 and $(8) for the years ended 2016, 2015 and 2014, respectively	—	(11)	12
Pension/OPEB adjustment, net of tax (expense) benefit of $9, $(16), and $101 for the years ended 2016, 2015 and 2014, respectively	(13)	24	(147)
Other Comprehensive Income (Loss), net of tax	29	(12)	(165)
COMPREHENSIVE INCOME	$47	$844	$595

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

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$11	$12
Accounts Receivable	276	217
Accounts Receivable—Affiliated Companies	205	276
Short-Term Loan to Affiliate	87	363
Fuel	326	463
Materials and Supplies, net	381	363
Derivative Contracts	162	223
Prepayments	10	25
Other	2	7
Total Current Assets	1,460	1,949
PROPERTY, PLANT AND EQUIPMENT	12,655	11,354
Less: Accumulated Depreciation and Amortization	(4,135)	(3,227)
Net Property, Plant and Equipment	8,520	8,127
NONCURRENT ASSETS		
NDT Fund	1,859	1,754
Long-Term Investments	102	119
Goodwill	16	16
Other Intangibles	98	102
Other Special Funds	53	55
Derivative Contracts	24	77
Other	61	51
Total Noncurrent Assets	2,213	2,174
TOTAL ASSETS	$12,193	$12,250

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

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2016	2015
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$—	$553
Accounts Payable	539	432
Accounts Payable—Affiliated Companies	25	33
Derivative Contracts	8	76
Accrued Interest	20	25
Other	88	107
Total Current Liabilities	680	1,226
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	2,170	2,347
Asset Retirement Obligations	511	457
OPEB Costs	251	230
Derivative Contracts	3	16
Accrued Pension Costs	191	166
Long-Term Accrued Taxes	77	35
Other	129	87
Total Noncurrent Liabilities	3,332	3,338
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT	2,382	1,684
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,782	5,014
Accumulated Other Comprehensive Loss	(211)	(240)
Total Member's Equity	5,799	6,002
TOTAL LIABILITIES AND MEMBER'S EQUITY	$12,193	$12,250

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2016	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$18	$856	$760
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	881	291	292
Amortization of Nuclear Fuel	203	213	200
Provision for Deferred Income Taxes and ITC	(208)	261	221
Interest Accretion on Asset Retirement Obligation	26	26	30
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	183	(143)	(93)
Renewable Energy Credit (REC) Compliance Accrual	109	104	69
Impairment Costs for Early Plant Retirements	102	—	—
Non-Cash Employee Benefit Plan Costs	39	48	13
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(26)	(38)	(166)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	31	62	19
Margin Deposit	(76)	122	(22)
Accounts Receivable	(71)	63	(15)
Accounts Payable	(22)	(46)	(59)
Accounts Receivable/Payable-Affiliated Companies, net	6	(84)	220
Other Current Assets and Liabilities	10	(36)	(6)
Employee Benefit Plan Funding and Related Payments	(13)	(11)	(7)
Other	63	18	(31)
Net Cash Provided By (Used In) Operating Activities	1,255	1,706	1,425
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,343)	(1,117)	(626)
Purchase of Emissions Allowances and RECs	(99)	(106)	(101)
Proceeds from Sales of Available-for-Sale Securities	739	1,422	1,557
Investments in Available-for-Sale Securities	(766)	(1,455)	(1,573)
Short-Term Loan—Affiliated Company, net	276	221	206
Other	46	34	13
Net Cash Provided By (Used In) Investing Activities	(1,147)	(1,001)	(524)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Long-Term Debt	700	—	—
Cash Dividend Paid	(250)	(400)	(895)
Redemption of Long-Term Debt	(553)	(300)	—
Other	(6)	(2)	(3)
Net Cash Provided By (Used In) Financing Activities	(109)	(702)	(898)
Net Increase (Decrease) in Cash and Cash Equivalents	(1)	3	3
Cash and Cash Equivalents at Beginning of Period	12	9	6
Cash and Cash Equivalents at End of Period	$11	$12	$9
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$50	$393	$68

Interest Paid, Net of Amounts Capitalized	$81	$116	$119
Accrued Property, Plant and Equipment Expenditures	$244	$114	$91

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2014	$ 2,214	$ (986)	$ 4,693	$ (63)	$ 5,858
Net Income	—	—	760	—	760
Other Comprehensive Income (Loss), net of tax (expense) benefit of $121	—	—	—	(165)	(165)
Comprehensive Income					595
Cash Dividends Paid	—	—	(895)		(895)
Balance as of December 31, 2014	$ 2,214	$ (986)	$ 4,558	$ (228)	$ 5,558
Net Income	—	—	856	—	856
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	(12)	(12)
Comprehensive Income					844
Cash Dividends Paid	—	—	(400)	—	(400)
Balance as of December 31, 2015	$ 2,214	$ (986)	$ 5,014	$ (240)	$ 6,002
Net Income	—	—	18	—	18
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(32)	—	—	—	29	29
Comprehensive Income					47
Cash Dividends Paid	—	—	(250)	—	(250)
Balance as of December 31, 2016	$ 2,214	$ (986)	$ 4,782	$ (211)	$ 5,799

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated (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:

- Public Service Electric and Gas Company (PSE&G)—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the 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.
- PSEG Power LLC (Power)—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses through competitive energy sales in well-developed energy markets and fuel supply functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. Power's subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) 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 Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 4. Variable Interest Entities. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All intercompany accounts and transactions are eliminated in consolidation.

PSE&G and Power also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. PSE&G and Power consolidate their portion of any revenues and expenses related to their respective jointly-owned facilities in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G's financial statements reflect the economic effects of regulation. PSE&G defers the recognition of costs (a Regulatory Asset) or records the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities becomes no longer probable as a result of changes in regulation and/or competitive position, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G's transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 6. Regulatory Assets and Liabilities.

Derivative Instruments

Each company uses derivative instruments to manage risk pursuant to its business plans and prudent practices.

Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing the contract's market liquidity. PSEG has determined that contracts to purchase and sell certain products do not meet

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the definition of a derivative under the current authoritative guidance since they do not provide for net settlement, or the markets are not sufficiently liquid to conclude that physical forward contracts are readily convertible to cash.
Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for derivatives that are designated as normal purchases and normal sales (NPNS). Further, derivatives that qualify for hedge accounting can be designated as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings.

For derivative contracts that do not qualify or are not designated as cash flow or fair value hedges or as NPNS, changes in fair value are recorded in current period earnings. PSEG does not currently elect fair value or cash flow hedge accounting on its commodity derivative positions.

Contracts that qualify for, and are designated, as NPNS are accounted for upon settlement. Contracts which qualify for NPNS are contracts for which physical delivery is probable, they will not be financially settled, and the quantities under contract are expected to be used or sold in the normal course of business over a reasonable period of time.

For additional information regarding derivative financial instruments, see Note 16. Financial Risk Management Activities.

Revenue Recognition

PSE&G’s regulated electric and gas revenues are recorded primarily based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Regulated revenues from the transmission of electricity are recognized as services are provided based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of estimated revenue requirement with rates effective January 1 of each year. After completion of the annual period ending December 31, PSE&G files a true-up whereby it compares its actual revenue requirement to the original estimate to determine any over or under collection of revenue. PSE&G records the estimated financial statement impact of the difference between the actual and the filed revenue requirement as a refund or deferral for future recovery when such amounts are probable and can be reasonably estimated in accordance with accounting guidance for rate-regulated entities.

The majority of Power’s revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power’s revenue also includes changes in the value of energy derivative contracts that are not designated as NPNS. See Note 16. Financial Risk Management Activities for further discussion.

PJM Interconnection, L.L.C. (PJM), the Independent System Operator-New England (ISO-NE) and the New York Independent System Operator (NYISO) facilitate the dispatch of energy and energy-related products. Power generally reports electricity sales and purchases conducted with those individual ISOs on a net hourly basis in either Revenues or Energy Costs in its Consolidated Statement of Operations, the classification of which depends on the net hourly activity. Capacity revenue and expense is also reported net based on Power’s monthly net sale or purchase position in the individual ISOs.

PSEG LI is the primary beneficiary of Long Island Electric Utility Servco, LLC (Servco). For transactions in which Servco acts as principal, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. See Note 4. Variable Interest Entities for further information.

Depreciation and Amortization

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or FERC. The depreciation rate stated as a percentage of original cost of depreciable property was as follows:

	2016 Avg Rate		2015 Avg Rate		2014 Avg Rate	
PSE&G Depreciation Rate	2.45	%	2.46	%	2.47	%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power calculates depreciation on generation-related assets under the straight-line method based on the assets' estimated useful lives. The estimated useful lives are:

- general plant assets—3 years to 20 years
- fossil production assets—30 years to 70 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years
- solar assets—25 years

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized During Construction (IDC)

AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. IDC represents the cost of debt used to finance construction at Power. The amount of AFUDC or IDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate AFUDC or IDC for the years ended December 31, 2016, 2015 and 2014 were as follows:

	AFUDC/IDC Capitalized					
	2016		2015		2014	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
PSE&G	$66	7.81 %	$65	8.01 %	$44	8.09 %
Power	$54	4.87 %	$27	5.14 %	$24	5.14 %

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG's subsidiaries based on the taxable income or loss of each subsidiary in accordance with a tax sharing agreement between PSEG and each of its affiliated subsidiaries. Allocations between PSEG and its subsidiaries are recorded through intercompany accounts. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 20. Income Taxes for further discussion.

Impairment of Long-Lived Assets

Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, including prolonged periods of adverse commodity and capacity prices or a current expectation that a long-lived asset will be sold or disposed of significantly before the end of its previously estimated useful life, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's or asset group's carrying amount exceeds the associated undiscounted estimated future cash flows, the asset/asset group is considered impaired to the extent that its fair value is less than its carrying amount. An impairment would result in a reduction of the value of the long-lived asset/asset group through a non-cash charge to earnings. See Note 3. Early Plant Retirements for more information.

For Power, cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generation units are generally evaluated at a regional portfolio level (PJM, NYISO, ISO-NE) along with cash flows generated from the customer supply and risk management activities, inclusive of cash flows from contracts, including those that are accounted for as derivatives and meet the NPNS scope exception. In certain cases, generation assets are evaluated on an individual basis where those assets are individually contracted on a long-term basis with a third party and operations are independent of other generation assets (typically Power’s solar plants and Kalaeloa).

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

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Accounts Receivable—Allowance for Doubtful Accounts

PSE&G's accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G's best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

Materials and Supplies and Fuel

PSE&G's and Power's materials and supplies are carried at average cost and charged to inventory when purchased and expensed or capitalized to Property, Plant and Equipment, as appropriate, when installed or used. Fuel inventory at Power is valued at the lower of average cost or market and includes stored natural gas, coal, fuel oil and propane used to generate power and to satisfy obligations under Power's gas supply contracts with PSE&G. The costs of fuel, including transportation costs, are included in inventory when purchased and charged to Energy Costs when used or sold. The cost of nuclear fuel is capitalized within Property, Plant and Equipment and amortized to fuel expense using the units-of-production method.

Property, Plant and Equipment

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Power capitalizes costs, including those related to its jointly-owned facilities, which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets' environmental safety or efficiency. All other environmental expenditures are expensed as incurred. Power also capitalizes spare parts that meet specific criteria. Capitalized spares are depreciated over the remaining lives of their associated assets.

Available-for-Sale Securities

These securities comprise the Nuclear Decommissioning Trust (NDT) Fund, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power's nuclear facilities and amounts that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans.

Realized gains and losses on available-for-sale securities are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 9. Available-for-Sale Securities for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plans

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing services based upon the security type as reported by the trustee at the measurement date (December 31) for all plan assets.

PSEG recognizes a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and OPEB liabilities. This receivable is presented separately on the Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted.

Pursuant to the OSA, Servco records expense only to the extent of its contributions to its pension plan trusts and for OPEB payments made to retirees.

See Note 12. Pension and Other Postretirement Benefits (OPEB) and Savings Plans for further discussion.

Basis Adjustment

PSE&G and Power have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on PSE&G’s and Power’s Consolidated Balance Sheets. The $986

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million is an addition to PSE&G's Common Stockholder's Equity and a reduction of Power's Member's Equity. These amounts are eliminated on PSEG's consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements.

Note 2. Recent Accounting Standards

New Standards Issued and Adopted

Stock Compensation-Improvements to Employee Share-Based Payment Accounting

This accounting standard was issued to simplify aspects of the accounting for share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the Statement of Cash Flows.

Under the new guidance, all excess tax benefits and tax deficiencies related to employee share-based payments will be recognized in income tax expense rather than recognized in additional paid in capital. In the Statement of Cash Flows, excess tax benefits and deficiencies will be classified with other income tax cash flows as an operating activity rather than a financing activity as currently classified. In addition, the minimum statutory tax withholding requirements were simplified in order to facilitate equity classification of the award.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early adoption is permitted for an entity in any interim or annual period. An entity that elects early adoption must adopt all of the amendments in the same period; however, the amendments within this update require different adoption methods. PSEG adopted this standard in the fourth quarter of 2016. The impact to the financial statements was immaterial.

Disclosure for Investments in Certain Entities that Calculate Net Asset Value (NAV) per Share

This accounting standard eliminates the requirement to categorize, in the fair value hierarchy, investments whose fair values are measured at NAV using the practical expedient provided in the fair value guidance. The practical expedient applies to investments in mutual funds or structures similar to a mutual fund for which there is not a readily determinable fair value. Although not required in the fair value hierarchy, sufficient information must be provided to allow for reconciliation between the fair value of assets categorized in the hierarchy and the balance sheet.

The standard is effective for annual and interim periods beginning after December 15, 2015 with early adoption permitted. PSEG adopted this standard in the fourth quarter 2016 on a retrospective basis and has reflected the effect of the new disclosure requirements in Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plan.

Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern

This accounting standard requires management to assess an entity's ability to continue as a going concern and provide related disclosures in certain circumstances. These disclosures are only required when conditions give rise to substantial doubt about an entity's ability to continue as a going concern within one year from the financial statement issuance date. The standard is effective for annual and interim periods beginning after December 15, 2016. PSEG adopted this standard in the fourth quarter of 2016; however, no disclosures were required this period based on the above criteria.

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard clarifies the principles for recognizing revenue and removes inconsistencies in revenue recognition requirements; improves comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provides 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 standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early application is permitted. PSEG expects the new guidance to result in more detailed disclosures of revenue compared to current guidance, and possibly changes in presentation. PSEG continues to evaluate all of its revenue streams and its contracts. Certain implementation issues continue to be debated and are currently being addressed by the AICPA’s Revenue Recognition Working Group and the FASB’s Transition Resource Group, including the ability to recognize revenue for certain contracts where there is uncertainty regarding collection from customers and accounting for contributions in aid of construction. As the ultimate impact of the new standard has not yet been determined, PSEG has not elected its transition method.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method. Under the new guidance, equity investments (other than those accounted for using the equity method) will be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). Entities that have elected the fair value option for financial liabilities will present changes in fair value due to a change in their own credit risk through Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG is currently analyzing the impact of this standard on our financial statements; however, PSEG expects increased volatility in Net Income due to changes in fair value of our equity securities within the NDT and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor will classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. However, existing guidance related to leveraged leases will not change.

The standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Measurement of Credit Losses on Financial Instruments

This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however, this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early including in an interim period. PSEG is currently analyzing the impact of this standard on its financial statements.

Statement of Cash Flows: Restricted Cash

This accounting standard requires entities to explain the change during the period in the total of cash and cash equivalents and include amounts described as restricted cash or restricted cash equivalents in its reconciliation of beginning of period and end-of-period amounts in the Statement of Cash Flows.

The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt early including in an interim period. PSEG will include those amounts that are deemed to be restricted cash and restricted cash equivalents in its cash and cash equivalents balances in the statement of cash flows as well as disclosure regarding the nature of restricted amounts.

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Business Combinations: Clarifying the Definition of a Business
This accounting standard was issued mainly to provide more consistency in how the definition of a business is applied to acquisitions or dispositions. The new guidance will generally reduce the number of transactions that will require treatment as a business combination. The definition of a business now includes a filter that would consider whether substantially all the fair value of the gross assets acquired or disposed of is concentrated in a single identifiable asset or a group of similar identifiable assets. If this condition is met, the transaction would not qualify as a business.
The standard is effective for annual and interim periods beginning after December 15, 2017; however, entities may adopt it for transactions that have closed before the effective date but have not been reported in financial statements that have been issued or made available for issuance. PSEG is currently evaluating the impact of this standard on its financial statements; however, PSEG does not expect this guidance to materially impact its financial statements upon adoption.
Simplifying the Test for Goodwill Impairment
This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit’s fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.
An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG is currently assessing the impact of this guidance upon its financial statements.
Note 3. Early Plant Retirements
On October 3, 2016, Power determined that it would cease generation operations of the existing coal/gas units at the Hudson and Mercer generating stations on June 1, 2017. Power has filed deactivation notices with PJM for these existing units at both stations and final must-offer exception requests for the 2020-2021 PJM capacity auction to the PJM Independent Market Monitor. Power expects the units to continue to be available to generate electricity and receive previously cleared capacity payments through the date the units cease operations. The exact timing of the early retirement of these units may be impacted by operational and other conditions that could subsequently arise.
PSEG and Power undertake their annual five-year strategic planning process primarily during the third and fourth quarters of each year. The primary factors considered during this process that contributed to the decision to retire these units early include significant declines in revenues and margin caused by a sustained period of depressed wholesale power prices and reduced capacity factors caused by lower natural gas prices making coal generation less economically competitive than natural gas-fired generation. Despite experiencing recent warmer than normal weather in PJM this summer, Power did not experience the usual increase in electricity prices in PJM as it had in past hot summers. This trend has a further adverse economic impact to these units because they generally dispatch and earn energy margin on peak hot and cold days. In addition, the upcoming PJM capacity auction in May 2017 for the capacity period from June 2020 to May 2021 will be the first to require all generating units to meet the increased operating performance standards of PJM’s new capacity performance regulations. During the current annual five-year strategic planning process, Power determined, on October 3, 2016, that the costs to upgrade the existing units at the Hudson and Mercer stations to comply with these higher reliability standards to be too significant and not economic given current market conditions, including anticipated future capacity prices, current forward energy prices and past operational performance results of the units. While these units have the capability to run on both coal and natural gas, they have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units.

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The decision to retire the Hudson and Mercer units early had and will continue to have a material effect on PSEG’s and Power’s results of operations. In 2016, PSEG and Power recognized the following pre-tax charges in Energy Costs, Operation and Maintenance and Depreciation expense during the period following the announcement of the early retirement of the plants:

	Year Ended December 31, 2016
	Millions
Statement of Operations Expense (pre-tax)	
Energy Costs	
Coal Inventory Lower of Cost or Market Adjustments and Capacity Penalties	$ 62
Operation and Maintenance	
Materials and Supplies Obsolescence	31
Write-down of Construction Work in Progress	14
Other (A)	8
Depreciation and Amortization	
Depreciation including Asset Retirement Costs	571
Total Pre-Tax Expense	$ 686

(A) Includes severance and miscellaneous costs. Power recorded $7 million of severance expense which it expects to pay in 2017.

In addition to these charges, Power expects to recognize the remaining Depreciation and Amortization of $958 million in 2017 due to the significant shortening of the expected economic useful lives of Hudson and Mercer. Additional employee-related salary continuance and severance costs and various miscellaneous costs may also be incurred during the period prior to retirement. Finally, Power currently anticipates using the sites for alternative industrial activity. However, if Power determines not to use the sites for alternative industrial activity, the early retirement of the units at such sites would trigger obligations under certain environmental regulations, including possible remediation. The amounts for any such environmental remediation are neither currently probable nor estimable but may be material.

Because the Hudson and Mercer generating units will cease operations significantly before the end of their previously estimated useful lives, Power performed a recoverability test for its portfolio of generating assets in the PJM region to determine if an impairment exists. As of September 30, 2016, the estimated undiscounted future cash flows of the PJM asset group exceeded the carrying amount and no impairment was identified. For additional information on impairment of long-lived assets, see Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies.

In addition, Power has reduced the estimated useful life of Bridgeport Harbor Station unit 3 from 2025 to the summer of 2021 as it is more likely than not it will retire the unit by this time. The change in the estimated useful life is not expected to have a material impact on Power’s future financial results. PSEG and Power continue to monitor their Keystone and Conemaugh generating stations to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG’s and Power’s control and may impact their ability to operate or maintain these assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG’s and Power’s future financial results.

Note 4. Variable Interest Entities (VIEs)

VIEs 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 was pledged as collateral to a trustee. PSE&G acted as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds were remitted to Transition Funding and Transition Funding II and were used for interest and principal payments on the transition bonds and related costs. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remained with these VIEs. During 2016,

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Transition Funding and Transition Funding II refunded final over-collected transition charges to ratepayers and as of December 31, 2016 the securitization program was completed.
VIE for which PSEG LI is the Primary Beneficiary
PSEG LI consolidates 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.
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 O&M Expense, respectively. In 2016, 2015 and 2014, Servco recorded $410 million, $375 million and $389 million, 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 Consolidated Statement of Operations.
Note 5. Property, Plant and Equipment and Jointly-Owned Facilities
Information related to Property, Plant and Equipment as of December 31, 2016 and 2015 is detailed below:

	PSE&G	Power	Other	PSEG Consolidated
	Millions			
2016				
Transmission and Distribution:				
Electric Transmission	$9,132	$—	$—	$ 9,132
Electric Distribution	7,974	—	—	7,974
Gas Transmission	89	—	—	89
Gas Distribution	6,369	—	—	6,369
Construction Work in Progress	1,501	—	—	1,501
Plant Held for Future Use	19	—	—	19
Other	439	—	—	439
Total Transmission and Distribution	25,523	—	—	25,523
Generation:				
Fossil Production	—	7,096	—	7,096
Nuclear Production	—	2,516	—	2,516
Nuclear Fuel in Service	—	783	—	783
Other Production-Solar	591	687	—	1,278
Construction Work in Progress	—	1,483	—	1,483
Total Generation	591	12,565	—	13,156
Other	233	90	335	658
Total	$26,347	$12,655	$335	$ 39,337

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	PSE&G	Power	Other	PSEG Consolidated
	Millions			
2015				
Transmission and Distribution:				
Electric Transmission	$7,554	$—	$—	$ 7,554
Electric Distribution	7,553	—	—	7,553
Gas Transmission	89	—	—	89
Gas Distribution	5,875	—	—	5,875
Construction Work in Progress	1,459	—	—	1,459
Plant Held for Future Use	26	—	—	26
Other	411	—	—	411
Total Transmission and Distribution	22,967	—	—	22,967
Generation:				
Fossil Production	—	7,005	—	7,005
Nuclear Production	—	2,202	—	2,202
Nuclear Fuel in Service	—	785	—	785
Other Production-Solar	569	389	—	958
Construction Work in Progress	—	892	—	892
Total Generation	569	11,273	—	11,842
Other	196	81	408	685
Total	$23,732	$11,354	$408	$ 35,494

PSE&G and Power have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities to which they are a party. All amounts reflect PSE&G’s or Power’s share of the jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

		As of December 31,			
		2016		2015	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
PSE&G:					
Transmission Facilities	Various	$169	$ 65	$166	$ 72
Power:					
Coal Generating:					
Conemaugh	23 %	$408	$ 166	$404	$ 154
Keystone	23 %	$409	$ 176	$408	$ 163
Nuclear Generating:					
Peach Bottom	50 %	$1,272	$ 306	$1,219	$ 262
Salem	57 %	$1,077	$ 304	$990	$ 276
Nuclear Support Facilities	Various	$238	$ 71	$226	$ 60
Pumped Storage Facilities:					
Yards Creek	50 %	$42	$ 25	$42	$ 24
Merrill Creek Reservoir	14 %	$1	$ —	$1	$ —

Power holds undivided ownership interests in the jointly-owned facilities above. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power’s share of expenses for the jointly-owned facilities is included in the appropriate expense category. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

GenOn Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. Jersey Central Power & Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Owners Group is the owner-operator of this facility. The operator submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Note 6. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP for regulated utilities as described in Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies. PSE&G has deferred certain costs based on rate orders issued by the BPU or FERC or based on PSE&G's experience with prior rate cases. Most of PSE&G's Regulatory Assets and Liabilities as of December 31, 2016 are supported by written orders, either explicitly or implicitly through the BPU's treatment of various cost items. These costs will be recovered and amortized over various future periods.

Regulatory Assets and other investments and costs incurred under our various infrastructure filings and clause mechanisms are subject to prudence reviews and can be disallowed in the future by regulatory authorities. To the extent that collection of any infrastructure or clause mechanism revenue, Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.

PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31,		
	2016	2015	Recovery/Refund Period
	Millions		
Regulatory Assets			
Current			
New Jersey Clean Energy Program	$142	$142	Annual filing for recovery (2)
Weather Normalization Clause (WNC)	49	10	Annual filing for recovery (2)
Underrecovered Electric Energy Costs—Basic Generation Service	2	11	Annual filing for recovery (1) (2)
Other	6	1	Various
Total Current Regulatory Assets	$199	$164	
Noncurrent			
Pension and OPEB Costs	$1,403	$1,270	Various
Deferred Income Taxes	507	467	Various
Manufactured Gas Plant (MGP) Remediation Costs	403	431	Various (2)
Storm Damage Deferrals	239	233	To be determined
Electric Transmission and Gas Cost of Removal	189	160	Through depreciation rates
Remediation Adjustment Charge (RAC) (Other SBC)	180	174	Through 2022 (1) (2)
Conditional Asset Retirement Obligation	157	152	Various

Green Program Recovery Charges (GPRC)	91	104	Various (1) (2)
Unamortized Loss on Reacquired Debt and Debt Expense	61	67	Over remaining debt life
Mark-to-Market (MTM) Contracts	—	63	Through 2017
Other	89	75	Various
Total Noncurrent Regulatory Assets	$3,319	$3,196	
Total Regulatory Assets	$3,518	$3,360	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31,		
	2016	2015	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Current			
FERC Formula Rate True-up	$34	$19	Annual filing for recovery (1) (2)
GPRC	28	36	Annual filing for recovery (1) (2)
Gas Margin Adjustment Clause	11	13	Annual filing for recovery (1) (2)
Overrecovered Gas Costs —Basic Gas Supply Service	6	1	Annual filing for recovery (1) (2)
Overrecovered Non-Utility Generation Charge (NGC)	5	1	Annual filing for recovery (1) (2)
Societal Benefit Clause (SBC)	4	31	Various (1) (2)
Stranded Costs (including $42 in 2015 related to VIEs)	—	64	Through December 2016 (2)
Total Current Regulatory Liabilities	$88	$165	
Noncurrent			
Electric Distribution Cost of Removal	$94	$122	Through depreciation rates
MTM Contracts	20	—	Various
FERC Formula Rate True-up	1	49	Annual filing for recovery (1) (2)
Other	3	4	Various
Total Noncurrent Regulatory Liabilities	$118	$175	
Total Regulatory Liabilities	$206	$340	

(1) Recovered/Refunded with interest.
(2) Recoverable/Refundable per specific rate order.

All Regulatory Assets and Liabilities are excluded from PSE&G's rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- Conditional Asset Retirement Obligation: These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.
- Deferred Income Taxes: These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices.
- Electric and Gas Cost of Removal: PSE&G accrues and collects in rates for the cost of removing, dismantling and disposing of its transmission and distribution assets upon retirement. The regulatory asset or liability for non-legally required cost of removal represents the difference between amounts collected in rates and costs actually incurred.
- FERC Formula Rate True-up: Overcollection or undercollection of transmission earnings calculated using a FERC approved formula.
- Gas Margin Adjustment Clause: This mechanism credits Firm delivery customers for net distribution margin revenue collected from Transportation Gas Service Non-Firm (TSG-NF) delivery customers. The balance represents the difference between the net margin collected from the TSG-NF Customers versus bill credits provided to Firm delivery customers.
- GPRC: These costs are amounts associated with various renewable energy and energy efficiency programs. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program, Energy Efficiency Economic (EEE) Extension Program, EEE Extension II Program, the Demand Response Program, Solar Generation Investment Program (Solar 4 All), Solar 4 All Extension, Solar 4 All Extension II, Solar Loan II Program and Solar Loan III Program.
- MGP Remediation Costs: Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for manufactured gas plants that are probable of recovery in future rates. Once

these costs are incurred, they are recovered through the RAC in the SBC.

- MTM Contracts: The estimated fair value of gas hedge contracts and gas cogeneration supply contract. The regulatory asset/liability is offset by a derivative asset/liability and, with respect to the gas hedge contracts only, an intercompany receivable/payable on the Consolidated Balance Sheets.

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- New Jersey Clean Energy Program: The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2017. The BPU funding requirements are recovered through the SBC.
- NGC: These costs represent the difference between the cost of non-utility generation and the benefit realized from the energy received at market rates.
- Overrecovered Gas Costs: These costs represent the overrecovered amounts associated with Basic Gas Supply Service (BGSS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for gas customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for PSE&G’s operations. For BGSS, interest is accrued only on overrecovered balances.
- Pension and OPEB Costs: Pursuant to the adoption of accounting guidance for employers’ defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs are amortized and recovered in future rates.
- RAC (Other SBC): Costs incurred to clean up manufactured gas plants which are recovered over seven years.
- SBC: The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act, includes costs related to PSE&G’s electric and gas business as follows: (1) the Universal Service Fund (USF); (2) Energy Efficiency and Renewable Energy Programs; (3) Electric bad debt expense; and (4) the RAC for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.
- Storm Damage Deferrals: Costs incurred in the cleanup of major storms in 2010 through 2016. As of December 31, 2016, this includes the $220 million of storm costs, net of insurance recoveries, primarily as a result of Hurricane Irene and Superstorm Sandy, approved for recovery in a future base rate case proceeding under a BPU order received in September 2014.
- Stranded Costs: As of December 31, 2015, the balance represented overrecovered costs, which were collected by PSE&G as servicer on behalf of Transition Funding and Transition Funding II, respectively through the securitization transition charges authorized by the BPU in irrevocable financing. Collected funds were remitted to Transition Funding and Transition Funding II and used for interest and principal payments on the transition bonds and related costs and taxes. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remained. In 2016, PSE&G refunded over-collections from customers associated with Stranded Costs and as of December 31, 2016, there were no remaining Regulatory Assets or Liabilities associated with this program.
- Unamortized Loss on Reacquired Debt and Debt Expense: Represents losses on reacquired long-term debt and expenses associated with issuances of new debt, which are recovered through rates over the remaining life of the debt.
- Underrecovered Electric Energy Costs: These costs represent the underrecovered amounts associated with BGS, as approved by the BPU. For BGS, interest is accrued on both overrecovered and underrecovered balances.
- WNC: This represents the over- or under- collection of gas margin refundable or recoverable under the BPU’s weather normalization clause. The WNC requires PSE&G to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred. Over recoveries are refunded to customers in the next winter season while under recoveries (subject to an earnings cap) are collected from customers in the next winter season.

Significant 2016 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- Transmission Formula Rate Filings—In June 2016, PSE&G filed its 2015 true-up adjustment pertaining to its transmission formula rates in effect for 2015. This resulted in an adjustment of $34 million less than the 2015 originally filed revenues primarily due to the impact of bonus depreciation legislation enacted after PSE&G filed its 2015 formula rate requirement in October 2014. PSE&G had recognized the majority of this adjustment in its Consolidated Statement of Operations for the year ended December 31, 2015. For the year ended December 31, 2016, PSE&G does not anticipate a significant true-up adjustment to its 2016 Annual Formula rate. That true-up will be filed

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by no later than June 15, 2017. In October 2016, the 2017 Annual Formula Rate Update was filed with FERC and requests approximately $121 million in increased annual transmission revenues effective January 1, 2017, subject to true-up.

- Energy Strong Recovery Filing—In March and September of each year, PSE&G files with the BPU for base rate recovery of Energy Strong investments which include a return of and on its investment. In June 2016, PSE&G updated its March cost recovery petition to include Energy Strong investments in service as of May 31, 2016 which represents estimated annual increases in electric and gas revenues of $16 million and $23 million, respectively. In August 2016, the BPU approved these rate increases effective September 1, 2016.

In September 2016, 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, 2016 through November 30, 2016. In February 2017, the BPU approved PSE&G's request for an annualized increase in electric revenue requirements of $12 million with rates effective March 1, 2017.

- Gas System Modernization Program (GSMP)—In December 2016, the BPU approved PSE&G's initial annual GSMP cost recovery petition which results in an annual revenue increase of $10 million effective January 1, 2017. This increase represents the return of and on investment for GSMP infrastructure in service through September 30, 2016.
- Green Program Recovery Charges (GPRC)—Each year PSE&G files with the BPU for annual recovery of its Green Program investments which include a return on its investment and recovery of expenses. In July 2016, PSE&G filed its 2016 GPRC cost recovery petition requesting recovery for the nine combined components of the electric and gas GPRC. In September 2016, the BPU approved rates on a provisional basis effective October 1, 2016 designed to recover approximately $44 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs.

In November 2016, the BPU approved PSE&G's petition for a Solar 4 All Extension II Program for an additional 33 MWs of solar development on brownfields and closed landfills. The order allows PSE&G to extend the program under the same clause recovery process as its existing Solar 4 All Programs, with an estimated initial capital investment (excluding AFUDC) of approximately $80 million with a 9.75% ROE. The Solar 4 All Extension II Program is the tenth component of the GPRC.

- BGSS—In June 2016, PSE&G made its annual BGSS filing with the BPU requesting a reduction of $87 million in annual BGSS revenues. In September 2016, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 40 cents to 34 cents per therm effective October 1, 2016. The rate is subject to final settlement. In December 2016, PSE&G filed with the BPU for a self-implementing two-month bill credit of 7.5 cents per therm for the months of January and February 2017. In February 2017, PSE&G filed with the BPU to extend the self-implementing bill credit of 7.5 cents per therm to customers through March 2017. The 3-month bill credits are estimated to provide approximately $47 million in customer credits. The specific amount returned will depend on actual usage over that period.
- Weather Normalization Clause—In July 2016, PSE&G filed a petition requesting approval to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period. The deficiency gas revenues would be collected from customers over the 2016-2017 and 2017-2018 Winter Periods (October 1 through May 31). In September 2016, the BPU approved PSE&G's filing on a provisional basis with respect to the $54 million in deficiency revenues to be collected from customers effective October 1, 2016. This matter is pending.
- Remediation Adjustment Charge (RAC)—In April 2016, the BPU approved PSE&G's filing with respect to its RAC 23 petition allowing recovery of $54 million effective May 7, 2016 related to net Manufactured Gas Plant expenditures from August 1, 2014 through July 31, 2015. In November 2016, PSE&G filed a RAC 24 Petition with the BPU requesting recovery of $41 million of net Manufactured Gas Plant expenditures from August 1, 2015 through July 31, 2016. This matter is pending.
- Universal Service Fund (USF)/Lifeline—In September 2016, the BPU approved rates set to recover state-wide costs incurred by New Jersey electric and gas distribution companies under the State's USF/Lifeline energy assistance programs effective October 1, 2016. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on its Consolidated Statement of Operations.

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Note 7. Long-Term Investments
Long-Term Investments as of December 31, 2016 and 2015 included the following:

	As of December 31,	
	2016	2015
	Millions	
PSE&G		
Life Insurance and Supplemental Benefits	$140	$150
Solar Loans	159	175
Other Investments	—	5
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	102	119
Energy Holdings		
Lease Investments	649	784
Total Long-Term Investments	$1,050	$1,233

(A) During the three years ended December 31, 2016, 2015 and 2014, dividends from these investments were $18 million, $16 million and $17 million, respectively.

Leases
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 Consolidated Balance Sheets. As an equity investor, Energy Holdings’ equity investments in the leases are comprised of the total expected lease receivables 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 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 Consolidated Balance Sheets.

During the third quarter of 2016, Energy Holdings completed its annual review of estimated residual values embedded in the NRG REMA, LLC (REMA) leveraged leases. The outcome indicated that the revised residual value estimates were lower than the recorded residual values and the decline was deemed to be other than temporary due to the adverse economic conditions experienced by coal generation in PJM, as discussed in Note 3. Early Plant Retirements, negatively impacting the economic outlook of the leased assets. As a result, a pre-tax write-down of $137 million was reflected in Operating Revenues in the quarter ended September 30, 2016, calculated by comparing the gross investment in the leases before and after the revised residual estimates. During the fourth quarter of 2016, Energy Holdings recorded a $10 million charge for its best estimate of loss as a result of the current liquidity issues facing REMA, which was reflected in Operating Revenues and is included in Gross Investments in Leases as of December 31, 2016. For additional information, see Note 8. Financing Receivables.

The following table shows Energy Holdings’ gross and net lease investment as of December 31, 2016 and 2015, respectively.

	As of December 31,	
	2016	2015
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$629	$631
Estimated Residual Value of Leased Assets	346	519
Total Investment in Rental Receivables	975	1,150
Unearned and Deferred Income	(326)	(366)
Gross Investments in Leases	649	784
Deferred Tax Liabilities	(674)	(724)
Net Investments in Leases	$(25)	$60

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The pre-tax income (loss) and income tax effects, excluding gains and losses on sales, related to investments in leases were as follows:

	Years Ended December 31,		
	2016	2015	2014
	Millions		
Pre-Tax Income (Loss) from Leases	$(135)	$ 12	$ 24
Income Tax Expense (Benefit) on Income from Leases	$(51)	$ 5	$ 32

Equity Method Investments
Power had the following equity method investments as of December 31, 2016 and 2015:

Name	As of December 31, 2016	2015	Location	% Owned
	Millions			
Power				
Keystone Fuels, LLC	$ 7	$ 16	PA	23%
Conemaugh Fuels, LLC	$ 8	$ 14	PA	23%
PennEast Pipeline	$ 11	$ 5	PA	10%
Kalaeloa	$ 76	$ 84	HI	50%

Note 8. Financing Receivables
PSE&G
PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding loans, including the noncurrent portion reported in Note 7. Long-Term Investments, by class of customer, none of which would be considered "non-performing."

Outstanding Loans by Class of Customer

Consumer Loans	As of December 31, 2016	2015
	Millions	
Commercial/Industrial	$164	$177
Residential	11	12
Total	$175	$189

Energy Holdings
Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $(25) million as of December 31, 2016 and $60 million as of December 31, 2015 (See Note 7. Long-Term Investments).

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The corresponding receivables associated with the lease portfolio are reflected as follows, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard & Poor's (S&P) as of December 31, 2016	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2016
	Millions
AA	$ 16
BBB+ — BBB-	316
BB-	133
CCC	164
Total	$ 629

The "BB-" and the "CCC" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of December 31, 2016, the gross investment in the leases of such assets, net of non-recourse debt, was $426 million, ($(131) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$ 134	64 %	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$ 83	64 %	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$ 55	17 %	1,711	Coal	CCC (A)	REMA
Conemaugh Station Units 1 and 2	PA	$ 55	17 %	1,711	Coal	CCC (A)	REMA
Shawville Station Units 1, 2, 3 and 4	PA	$ 99	100 %	596	Gas	CCC (A)	REMA

(A) REMA's parent company, GenOn Energy Inc. (GenOn), reported in August 2016 that GenOn did not expect to have sufficient liquidity to repay its senior unsecured notes due in June 2017. In January 2017, S&P further lowered its corporate credit rating on GenOn and its affiliates (including REMA) to "CCC - " from "CCC" reflecting the primary credit concern of the near-term maturity of GenOn's senior unsecured notes in June 2017 and expressed a negative outlook reflecting the continuing pressure on financial measures. In October 2016, Moody's downgraded the GenOn Corporate Family Rating to "Caa3" to reflect its high debt burden relative to cash flow.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. 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 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 and trigger certain material tax obligations which could wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit 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. Although all lease payments are current, PSEG cannot predict the outcome of GenOn's efforts to restructure its portfolio and improve its liquidity and the possible related impact on REMA. PSEG continues to monitor any changes to REMA's and GenOn's status and potential impacts on Energy Holdings' lease investments. If lease rejections or 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.

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Additional factors that 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 their affiliates and the quality and condition of assets under lease.

Note 9. Available-for-Sale Securities

NDT Fund

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is required to file periodic reports with the NRC demonstrating that its NDT Fund meets the formula-based minimum NRC funding requirements.

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power’s share of decommissioning costs related to its five nuclear units was estimated to be between $2.8 billion and $3.0 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2016 was approximately $454 million and is included in the Asset Retirement Obligation. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power. Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund.

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$705	$ 263	$ (11)	$957
Debt Securities				
Government	518	8	(6)	520
Corporate	337	4	(4)	337
Total Debt Securities	855	12	(10)	857
Other Securities	44	—	—	44
Total NDT Available-for-Sale Securities (A)	$1,604	$ 275	$ (21)	$1,858

(A) The NDT available-for-sale securities table excludes cash of $1 million which is part of the NDT Fund.

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$693	$ 185	$ (13)	$865
Debt Securities				
Government	483	8	(3)	488
Corporate	366	3	(10)	359
Total Debt Securities	849	11	(13)	847
Other Securities	42	—	—	42
Total NDT Available-for-Sale Securities	$1,584	$ 196	$ (26)	$1,754

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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 Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 8	$ 17
Accounts Payable	$ 5	$ 10

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

	As of December 31, 2016				As of December 31, 2015			
	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)	$120	$ (10)	$8	$ (1)	$151	$ (13)	$1	$ —
Debt Securities								
Government (B)	276	(6)	4	—	245	(2)	19	(1)
Corporate (C)	139	(3)	15	(1)	222	(7)	36	(3)
Total Debt Securities	415	(9)	19	(1)	467	(9)	55	(4)
NDT Available-for-Sale Securities	$535	$ (19)	$27	$ (2)	$618	$ (22)	$56	$ (4)

(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 December 31, 2016.

(B) Debt Securities (Government)—Unrealized losses on Power’s NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will 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 December 31, 2016.

(C) Debt Securities (Corporate)—Power’s investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since 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 December 31, 2016.

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

	Years Ended December 31,		
	2016	2015	2014
	Millions		
Proceeds from Sales (A)	$711	$1,397	$1,448
Net Realized Gains (Losses):			
Gross Realized Gains	$53	$97	$177
Gross Realized Losses	(32)	(37)	(23)
Net Realized Gains (Losses) on NDT Fund	$21	$60	$154

(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 Consolidated Statements of Operations. Net unrealized gains of $128 million (after-tax) are included in Accumulated Other Comprehensive Loss on PSEG's and Power's Consolidated Balance Sheets as of December 31, 2016.

The available-for-sale debt securities held as of December 31, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 15
1 - 5 years	257
6 - 10 years	193
11 - 15 years	50
16 - 20 years	60
Over 20 years	282
Total NDT Available-for-Sale Debt Securities	$ 857

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

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2016, other-than-temporary impairments of $28 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."

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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 bases for the securities held in the Rabbi Trust.

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$11	$ 11	$ —	$22
Debt Securities				
Government	105	—	(2)	103
Corporate	92	1	(2)	91
Total Debt Securities	197	1	(4)	194
Other Securities	1	—	—	1
Total Rabbi Trust Available-for-Sale Securities	$209	$ 12	$ (4)	$217

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$12	$ 10	$ —	$22
Debt Securities				
Government	108	1	(1)	108
Corporate	82	—	(1)	81
Total Debt Securities	190	1	(2)	189
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	$204	$ 11	$ (2)	$213

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 Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2016	As of December 31, 2015
	Millions	
Accounts Receivable	$ 5	$ 1
Accounts Payable	$ 3	$ —

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

	As of December 31, 2016				As of December 31, 2015			
	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 (B)	60	(2)	1	—	53	(1)	2	—
Corporate (C)	46	(2)	3	—	46	(1)	9	—
Total Debt Securities	106	(4)	4	—	99	(2)	11	—
Rabbi Trust Available-for-Sale Securities	$106	$ (4)	$ 4	$ —	$99	$ (2)	$11	$ —

(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 U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will 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 December 31, 2016.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2016.

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

	Years Ended December 31,		
	2016	2015	2014
	Millions		
Proceeds from Rabbi Trust Sales (A)	$113	$104	$467
Net Realized Gains (Losses):			
Gross Realized Gains	$6	$3	$4
Gross Realized Losses	(5)	(2)	(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.

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Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Consolidated Statements of Operations. Net unrealized gains of $5 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2016. The Rabbi Trust available-for-sale debt securities held as of December 31, 2016 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 8
1 - 5 years	44
6 - 10 years	44
11 - 15 years	9
16 - 20 years	8
Over 20 years	81
Total Rabbi Trust Available-for-Sale Debt Securities	$ 194

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. In 2016, there were no other-than-temporary impairments recognized on investments of the Rabbi Trust.
The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of December 31, 2016	As of December 31, 2015
	Millions	
PSE&G	$43	$ 42
Power	53	52
Other	121	119
Total Rabbi Trust Available-for-Sale Securities	$217	$ 213

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Note 10. Goodwill and Other Intangibles
As of December 31, 2016 and 2015, Power had goodwill of $16 million related to the Bethlehem Energy Center facility. Power conducted an annual review for goodwill impairment in the fourth quarter of 2016 and concluded that goodwill was not impaired. In addition to goodwill, as of December 31, 2016 and 2015, Power had intangible assets of $98 million and $102 million, respectively, related to emissions allowances and renewable energy credits. Emissions expense includes impairments of emissions allowances and costs for emissions, which is recorded as emissions occur. As load is served under contracts requiring energy from renewable sources, the related expense is recorded. Such expenses for the years ended December 31, 2016, 2015 and 2014 were as follows:

	Years Ended December 31,		
	2016	2015	2014
	Millions		
Emissions Expense	$14	$ 13	$ 10
Renewable Energy Expense	$95	$ 91	$ 59

Note 11. Asset Retirement Obligations (AROs)
PSEG, PSE&G and Power have recorded various AROs which represent legal obligations to remove or dispose of an asset or some component of an asset at retirement.
PSE&G has conditional AROs primarily for legal obligations related to the removal of treated wood poles and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G does not record an ARO for its protected steel and poly-based natural gas lines, as management believes that these categories of gas lines have an indeterminable life.
Power’s ARO liability primarily relates to the decommissioning of its nuclear power plants in accordance with NRC requirements. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 9. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power’s fossil generation units and solar facilities, including liabilities for removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites, and demolition of certain plants, and the restoration of the sites at which they reside, when the plants are no longer in service. To estimate the fair value of its AROs, Power uses a probability weighted, discounted cash flow model which, on a unit by unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on third-party decommissioning cost estimates, cost escalation rates, inflation rates and discount rates.
Updated cost studies are obtained triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When assumptions are revised to calculate fair values of existing AROs, the ARO balance and corresponding long-lived asset are adjusted which impact the amount of accretion and depreciation expense recognized in future periods. For PSE&G, Regulatory Assets and Regulatory Liabilities result when accretion and amortization are adjusted to match rates established by regulators resulting in the regulatory deferral of any gain or loss.

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The changes to the ARO liabilities for PSEG, PSE&G and Power during 2015 and 2016 are presented in the following table:

	PSEG	PSE&G	Power	Other
	Millions			
ARO Liability as of January 1, 2015	$743	$ 290	$450	$ 3
Liabilities Settled	(5)	(4)	(1)	—
Liabilities Incurred	14	1	12	1
Accretion Expense	26	—	26	—
Accretion Expense Deferred and Recovered in Rate Base (A)	16	16	—	—
Revision to Present Values of Estimated Cash Flows	(115)	(85)	(30)	—
ARO Liability as of December 31, 2015	$679	$ 218	$457	$ 4
Liabilities Settled	(13)	(9)	(4)	—
Liabilities Incurred	25	2	23	—
Accretion Expense	26	—	26	—
Accretion Expense Deferred and Recovered in Rate Base (A)	12	12	—	—
Revision to Present Values of Estimated Cash Flows	(3)	(10)	9	(2)
ARO Liability as of December 31, 2016	$726	$ 213	$511	$ 2

(A) Not reflected as expense in Consolidated Statements of Operations

During 2016, PSE&G recorded a reduction in its ARO liabilities primarily due to the impact of settlements and changes to cash flow estimates. These changes had no impact in PSE&G’s Consolidated Statement of Operations.

During 2016, Power recorded $23 million primarily related to new ARO liabilities at its fossil units coupled with new solar generation ARO liabilities.

Note 12. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors qualified and nonqualified pension plans and OPEB plans covering PSEG’s and its participating affiliates’ current and former employees who meet certain eligibility criteria. Eligible employees participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG’s two defined contribution plans described below.

PSEG, PSE&G and Power are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. For underfunded plans, the liability is equal to the difference between the plan’s benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, GAAP requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders’ Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses and prior service costs which had not been expensed.

For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For Power, the charge to Accumulated Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

Effective January 1, 2016, PSEG changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, PSEG calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, PSEG has elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans’ liability cash flows. PSEG believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans’ liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change was reflected prospectively. Pension and OPEB costs, net of amounts capitalized, were reduced by $34 million and $13 million, respectively, as compared to the 2016 amounts that would have been derived from applying PSEG’s 2015 and prior years’ methodology.

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As of December 31, 2016, PSEG merged its three qualified defined benefit pension plans (excluding Servco plans) into one plan, thereby also merging all of the pension plans' assets. No changes were made to the benefit formulas, the vesting provisions, or to the employees covered by the plans.
Amounts for Servco are not included in any of the following pension and OPEB benefit information for PSEG and its affiliates but rather are separately disclosed later in this note.
The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2016 and 2015. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$5,522	$5,722	$1,612	$1,638
Service Cost	109	123	17	22
Interest Cost	202	234	59	67
Actuarial (Gain) Loss (B)	219	(289)	127	(45)
Gross Benefits Paid	(282)	(268)	(57)	(70)
Plan Amendments	2	—	(4)	—
Benefit Obligation at End of Year (A)	$5,772	$5,522	$1,754	$1,612
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$5,039	$5,293	$374	$361
Actual Return on Plan Assets	403	(11)	32	(1)
Employer Contributions	33	25	71	84
Gross Benefits Paid	(282)	(268)	(57)	(70)
Fair Value of Assets at End of Year	$5,193	$5,039	$420	$374
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	$(579)	$(483)	$(1,334)	$(1,238)
Additional Amounts Recognized in the Consolidated Balance Sheets				
Noncurrent Assets (included in Other Special Funds)	$—	$14	$—	$—
Current Accrued Benefit Cost	(11)	(10)	(10)	(10)
Noncurrent Accrued Benefit Cost	(568)	(487)	(1,324)	(1,228)
Amounts Recognized	$(579)	$(483)	$(1,334)	$(1,238)
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (B)				
Prior Service Cost	$(63)	$(83)	$(14)	$(25)
Net Actuarial Loss	1,763	1,710	523	438
Total	$1,700	$1,627	$509	$413

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.
(B) Includes $679 million ($398 million, after-tax) and $658 million ($386 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2016 and 2015, respectively.

The pension benefits table above provides information relating to the funded status of the qualified, nonqualified pension and OPEB plans on an aggregate basis. As of December 31, 2016, PSEG had funded approximately 90% of its projected benefit obligation. This percentage does not include $217 million of assets in the Rabbi Trust as of December 31, 2016 which were used partially to fund the nonqualified pension plans. As of December 31, 2016, the nonqualified pension plans included in the projected benefit obligation in the above table were $161 million. The fair values of the Rabbi Trust assets are included in Other Special Funds on the Consolidated Balance Sheets.

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Accumulated Benefit Obligation
The accumulated benefit obligation for all PSEG's defined benefit pension plans was $5.6 billion as of December 31, 2016 and $5.4 billion as of December 31, 2015.
The following table provides the components of net periodic benefit cost for the years ended December 31, 2016, 2015 and 2014.

	Pension Benefits			Other Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2016	2015	2014	2016	2015	2014
	Millions					
Components of Net Periodic Benefit Cost (Credit)						
Service Cost	$109	$123	$104	$ 17	$ 22	18
Interest Cost	202	234	234	59	67	69
Expected Return on Plan Assets	(394)	(414)	(399)	(31)	(31)	(26)
Amortization of Net						
Prior Service Credit	(19)	(19)	(18)	(14)	(14)	(14)
Actuarial Loss	158	150	56	40	43	23
Net Periodic Benefit Cost (Credit)	$56	$74	$(23)	$ 71	$ 87	$ 70

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

	Pension Benefits			Other Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2016	2015	2014	2016	2015	2014
	Millions					
PSE&G	$29	$ 40	$(19)	$ 43	$ 55	$ 46
Power	16	21	(7)	23	27	20
Other	11	13	3	5	5	4
Total Benefit Cost (Credit)	$56	$ 74	$(23)	$ 71	$ 87	$ 70

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2016	2015	2016	2015
	Millions			
Net Actuarial (Gain) Loss in Current Period	$211	$136	$125	$(14)
Amortization of Net Actuarial Gain (Loss)	(158)	(150)	(40)	(43)
Prior Service Cost (Credit) in current period	1	—	(3)	—
Amortization of Prior Service Credit	19	19	14	14
Total	$73	$5	$96	$(43)

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Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2017 are as follows:

	Pension Benefits 2017	Other Benefits 2017
	Millions	
Actuarial (Gain) Loss	$97	$ 51
Prior Service Cost	$(18)	$ (11)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2016	2015	2014	2016	2015	2014
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.29%	4.54%	4.20%	4.37 %	4.58 %	4.21 %
Rate of Compensation Increase	3.61%	3.61%	3.61%	3.61 %	3.61 %	3.61 %
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	4.54%	4.20%	5.00%	4.58 %	4.21 %	5.01 %
Service Cost Interest Rate	4.81%	4.20%	5.00%	4.87 %	4.21 %	5.01 %
Interest Cost Interest Rate	3.75%	4.20%	5.00%	3.76 %	4.21 %	5.01 %
Expected Return on Plan Assets	8.00%	8.00%	8.00%	8.00 %	8.00 %	8.00 %
Rate of Compensation Increase	3.61%	3.61%	4.61%	3.61 %	3.61 %	4.61 %
Assumed Health Care Cost Trend Rates as of December 31						
Administrative Expense				3.00 %	3.00 %	3.00 %
Health Care Costs						
Immediate Rate				7.55 %	7.75 %	7.40 %
Ultimate Rate				4.75 %	4.75 %	5.00 %
Year Ultimate Rate Reached				2025	2025	2022
				Millions		
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$11	$12	$13
Postretirement Benefit Obligation				$191	$194	$201
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$(9)	$(10)	$(10)
Postretirement Benefit Obligation				$(160)	$(160)	$(165)

Plan Assets
The investments of pension and OPEB plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 17. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of the plans

are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. As of December 31, 2016, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 93% and 7%, respectively.

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The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2016 and 2015, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2016			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Cash Equivalents (A)	$107	$ 105	$ 2	$ —
Equities (B)				
Common Stock	944	944	—	—
Commingled (C)	1,387	1,247	140	—
Preferred Stock	1	1	—	—
Bonds (D)				
US Treasury	441	—	441	—
Government—Other	263	—	263	—
Corporate	836	—	836	—
Subtotal Fair Value	$3,979	$ 2,297	$ 1,682	$ —
Measured at net asset value practical expedient (C)				
Commingled—Equities	1,604			
Private Equity (E)	16			
Total Fair Value (F)	$5,599			

	Recurring Fair Value Measurements as of December 31, 2015			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Cash Equivalents (A)	$96	$ 95	$ 1	$ —
Equities (B)				
Common Stock	816	816	—	—
Commingled (C)	1,463	1,269	194	—
Bonds (D)				
US Treasury	322	—	322	—
Government—Other	279	—	279	—
Corporate	906	—	906	—
Subtotal Fair Value	$3,882	$ 2,180	$ 1,702	$ —
Measured at net asset value practical expedient (C)				
Commingled—Equities	1,504			
Private Equity (E)	19			
Total Fair Value (F)	$5,405			

(A)

Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active market (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

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(B) Common stocks and preferred stocks are measured using observable data in active markets and considered Level 1. Investments in certain commingled equity funds are measured at their published daily net asset value (NAV) available to investors; if they are redeemable daily without restrictions, they are classified as Level 1 or, if they have restrictions which prevent daily redemptions, they are classified as Level 2.

(C) In 2016, PSEG re-evaluated the classification, within the fair value hierarchy, of its commingled equity funds. As a result, PSEG determined that certain commingled funds in the amount of $1,698 million at December 31, 2015 should have been classified as Level 2 instead of Level 1, as previously presented for 2015, due to the funds having certain redemption restrictions which prevent daily redemptions at their published price. PSEG has determined that this error is immaterial to its previously filed financial reports and, accordingly, has corrected the error by revising the amounts disclosed for 2015 to report such investments as Level 2. In addition, as part of our implementation of the new accounting guidance on investments measured at fair value using NAV as a practical expedient in 2016, the majority of these same commingled equity funds have been removed from the fair value hierarchy as they are measured at fair value using the NAV per share (or its equivalent) practical expedient. See Note 2. Recent Accounting Standards. These funds do not meet the definition of readily determinable fair value due to limitations in published NAV (last business day of the month) and include certain redemption restrictions ranging from one to fifteen days advance notice prior to redemption days and limitations on withdrawals over 25% of the total fund. The objectives of these funds are mainly tracking the S&P Index or achieving long-term growth through investment in foreign equity securities and the MSCI Emerging Markets Index. As a result of the error correction for the $1,698 million that should have been classified as Level 2 for 2015 and $1,504 million that was removed from the fair value hierarchy as part of the new guidance on NAV practical expedient implementation, $194 million has been reclassified to Level 2 as of December 31, 2015.

(D) Fixed income securities include mainly investment grade corporate and municipal bonds, US Treasury obligations and Federal Agency asset-backed securities with a wide range of maturities. These investments are valued using an evaluated pricing approach 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 or the most recent quoted for similar securities which are a Level 2 measure.

(E) Private equity investments include various limited partnerships that invest in operating companies through acquisitions or developing a portfolio of non-US distressed investments. These investments are valued at NAV on an annual basis and have significant redemption restrictions preventing redemption until fund liquidation and limited ability to sell these investments. These investments have been removed from the fair value hierarchy in accordance with the new guidance on NAV practical expedient.

(F) Excludes net receivable of $14 million and $8 million at December 31, 2016 and 2015, respectively, which consists of interest and dividend, receivables and payables related to pending securities sales and purchases.

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	2016	2015
Equity Securities	70 %	70 %
Fixed Income Securities	28	28
Other Investments	2	2
Total Percentage	100%	100%

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. PSEG's latest asset/liability study indicates that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. Derivative financial instruments are used by the plans' investment managers primarily to adjust the fixed income duration of the portfolio and hedge the currency risk component of foreign investments. The expected long-term rate of return on plan assets was 8.0% for 2016 and will be 7.8% for 2017. This expected return was determined based on the study discussed above, including a premium for active management and considered the plans' historical annualized rate of return since inception, which was 9.3%.

Plan Contributions

PSEG plans to contribute $14 million into its OPEB plan during 2017.

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Estimated Future Benefit Payments
The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

Year	Pension Benefits	Other Benefits
	Millions	
2017	$310	$ 82
2018	307	86
2019	319	90
2020	331	94
2021	343	99
2022-2026	1,887	534
Total	$3,497	$ 985

401(k) Plans
PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act (ERISA) defined contribution retirement plans. Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans, not to exceed the IRS maximums, including any catch-up contributions for those employees age 50 and above. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.
The amount paid for employer matching contributions to the plans for PSEG, PSE&G and Power are detailed as follows:

	Thrift Plan and Savings Plan		
	Years Ended December 31,		
	2016	2015	2014
	Millions		
PSE&G	$ 24	$ 22	$ 20
Power	12	12	11
Other	5	5	5
Total Employer Matching Contributions	$ 41	$ 39	$ 36

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 4. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Consolidated Balance Sheet of PSEG.
The following table provides a roll-forward of the changes in Servco's benefit obligation and the fair value of its plan assets during the years ended December 31, 2016 and 2015. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

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	Pension Benefits		Other Benefits	
	2016	2015	2016	2015
		Millions		
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year	$211	$195	$375	$452
Service Cost	24	26	12	17
Interest Cost	9	9	17	21
Actuarial (Gain) Loss	14	(20)	50	(114)
Gross Benefits Paid	(1)	—	(2)	(1)
Plan Amendments	5	1	—	—
Benefit Obligation at End of Year (A)	$262	$211	$452	$375
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$97	$69	$—	$—
Actual Return on Plan Assets	10	(2)	—	—
Employer Contributions	28	30	2	1
Gross Benefits Paid	(1)	—	(2)	(1)
Fair Value of Assets at End of Year	$134	$97	$—	$—
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	$(128)	$(114)	$(452)	$(375)
Additional Amounts Recognized in the Consolidated Balance Sheets				
Accrued Pension Costs of Servco	$(128)	$(114)	N/A	N/A
OPEB Costs of Servco	N/A	N/A	(452)	(375)
Amounts Recognized (B)	$(128)	$(114)	$(452)	$(375)

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) Amounts equal to the accrued pension and OPEB costs of Servco are offset in Long-Term Receivable of VIE on PSEG's Consolidated Balance Sheets.

Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for 2016, 2015 and 2014 were $28 million, $30 million and $67 million, respectively. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2016. The OPEB-related revenues earned and costs incurred in 2016 was $2 million, and were immaterial 2015 and 2014.

The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits			Other Benefits		
	2016	2015	2014	2016	2015	2014
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.61%	4.92%	4.50%	4.71%	4.97%	4.60%
Rate of Compensation Increase	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Assumed Health Care Cost Trend Rates as of December 31						
Administrative Expense				5.00%	5.00%	5.00%
Health Care Costs						
Immediate Rate				7.55%	7.55%	7.33%

Ultimate Rate	4.75 %	4.75 %	5.00 %
Year Ultimate Rate Reached	2025	2025	2021
	Millions		
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs			
Postretirement Benefit Obligation	$97	$75	$160
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs			
Postretirement Benefit Obligation	$(75)	$(60)	$(106)

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Plan Assets
All the investments of Servco's pension plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 17. Fair Value Measurements for more information on fair value guidance. The Actuary maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Actuary to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans.
The following tables present information about Servco's investments measured at fair value on a recurring basis as of December 31, 2016 and 2015, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2016			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Commingled Equities (A)	$96	$ —	$ 96	$ —
Commingled Bonds (A)	38	—	38	—
Total	$134	$ —	$ 134	$ —

	Recurring Fair Value Measurements as of December 31, 2015			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Commingled Equities (A)	$68	$ —	$ 68	$ —
Commingled Bonds (A)	29	—	29	—
Total	$97	$ —	$ 97	$ —

(A) Investments in commingled equity and bond funds have a readily determinable fair value as they publish a daily NAV available to investors which is the basis for current transactions and contain certain redemption restrictions requiring advance notice of one to two days for withdrawals (Level 2). In 2016, PSEG re-evaluated the classification, within the fair value hierarchy, of its commingled funds. As a result, PSEG determined that the commingled equity funds should have been classified as Level 2 instead of Level 1, as previously presented for 2015, due to the funds having certain redemption restrictions which prevent daily redemptions at the published price. In addition to the advance notice of one or two days, redemption days may be limited to twice per month for certain funds. PSEG has determined that this error is immaterial to its previously filed financial reports and, accordingly, has corrected the error by revising the amounts disclosed for 2015 to report the commingled equity fund balance of $68 million as of December 31, 2015 as Level 2.

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans of Servco as of the measurement date, December 31:

As of
December

Investments	31, 2016	2015
Equity Securities	71 %	71 %
Fixed Income Securities	29	29
Total Percentage	100%	100%

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Servco utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. The results from Servco's latest asset/liability study indicated that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. The expected long-term rate of return on plan assets was 7.7% for 2016 and will be 7.6% for 2017. This expected return was determined based on the study discussed above, including a premium for active management.

Plan Contributions

Servco plans to contribute $35 million into its pension plan during 2017.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to Servco's plan participants:

Year	Pension Benefits	Other Benefits
	Millions	
2017	$2	$ 4
2018	3	6
2019	5	9
2020	7	11
2021	8	13
2022-2026	76	96
Total	$101	$ 139

Servco 401(k) Plans

Servco sponsors two 401(k) plans, which are defined contribution retirement plans subject to ERISA. Eligible non-represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan I (Thrift Plan I), and eligible represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan II (Thrift Plan II). Participants in the Plans may contribute up to 50% of their eligible compensation to these plans, not to exceed the IRS maximums, including any Catch-Up Contributions for those employees age 50 and above. Servco does not provide an employer match or core contribution for employees in Thrift Plan II. For employees in Thrift Plan I, Servco matches 50% of such employee contributions up to 8% of eligible compensation and provides core contributions (based on years of service and age) to employees who do not participate in Servco's Retirement Income Plan. The amounts expensed by Servco for employer matching contributions for the years ended December 31, 2016, 2015 and 2014 were $5 million, $4 million and $3 million, respectively, and pursuant to the OSA, Servco recognizes Operating Revenues for the reimbursement of these costs.

Note 13. 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 as a form of collateral. 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.

Power is subject to

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

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

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- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- the net position 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. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.
Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.
In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.
The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of December 31, 2016 and 2015.

	As of December 31, 2016	As of December 31, 2015
	Millions	
Face Value of Outstanding Guarantees	$1,806	$ 1,734
Exposure under Current Guarantees	$139	$ 172
Letters of Credit Margin Posted	$157	$ 122
Letters of Credit Margin Received	$99	$ 192
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$—	$ —
Counterparty Cash Margin Received	$(1)	$ (15)
Net Broker Balance Deposited (Received)	$57	$ (5)
Additional Amounts Posted		
Other Letters of Credit	$51	$ 51

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 16. 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 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 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 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.
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. Construction is complete. The CPG is awaiting EPA approval of the construction report, long-term monitoring plan and confirmatory sampling plan. PSE&G’s and Power’s combined share of the cost of that effort is approximately three percent. The remaining CPG members, PSE&G and Power included, 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 CPG, which consisted of 52 members as of December 31, 2016, 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 $190 million, which the CPG continues to incur. Of the estimated $190 million, as of December 31, 2016, the CPG had spent approximately $158 million, of which PSEG’s total share was approximately $11 million.
The CPG’s draft FS set forth various alternatives for remediating the lower Passaic River. It set 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 on an undiscounted basis. 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 ranged from approximately $518 million to $772 million. Based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G’s and Power’s estimated 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.

In March 2016, the EPA released its Record of Decision (ROD) for the FFS which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The ROD Remedy requires a bank-to-bank dredge ranging from approximately 5 to 30 feet deep in the federal navigation channel from River Mile 0 to River Mile 1.7 and an approximately 2.5 foot deep dredge everywhere else in the lower 8.3 miles of the river. An engineered cap approximately two feet thick will be placed over the dredged areas. Dredged sediments will be transported to facilities and landfills out-of-state. The EPA estimates the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation.

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Based upon the estimated cost of the ROD Remedy, PSEG's estimate of PSE&G's and Power's shares of that cost, and the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued an additional $36 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued an additional $8 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2016. As of December 31, 2016, these accruals bring the total liability to approximately $57 million, $46 million applicable to PSE&G and $11 million applicable to Power.

Also in March 2016, the EPA sent a notice letter to 105 PRPs, including PSE&G, all other past and present members of the CPG, including Occidental Chemical Corporation (OCC), and the towns of Newark, Kearny and Harrison and the Passaic Valley Sewerage Commission stating that the EPA wants to determine whether OCC, a successor company to Diamond Shamrock, would voluntarily perform the remedial design for the ROD Remedy. On September 30, 2016, OCC and the EPA executed an Administrative Settlement Agreement and Order on Consent for Remedial Design under which OCC agreed to conduct the remedial design for the ROD. With OCC's commitment to perform the remedial design, it is anticipated that the EPA will begin negotiation of a remedial action consent decree, under which OCC and the other "major PRPs" will implement and/or pay for the EPA's ROD Remedy for the lower 8.3 miles. The EPA has not defined "major PRPs."

On June 16, 2016, Tierra and Maxus, successors to Diamond Shamrock, filed for reorganization under Chapter 11 of the U.S. Bankruptcy Code. Although PSEG does not currently anticipate that the filing for bankruptcy by Tierra and Maxus will affect its allocable share or total liability for the Passaic River matter, PSEG, through the CPG and independently, will monitor the bankruptcy proceedings to identify any potential impact on PSEG's share of the costs.

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, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (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 PSEG's 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 U.S. Department of Commerce and the U.S. 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.

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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 $403 million and $460 million through 2021, including its $46 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 $403 million as of December 31, 2016. Of this amount, $81 million was recorded in Other Current Liabilities and $322 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $403 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. NJDEP, PSEG and EPA representatives have had discussions regarding whether sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.
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 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 May 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.
The EPA has structured the rule so that each state Permitting Director will continue to consider renewal permits for existing
power facilities on a case by case basis. In connection with the assessment of the best technology available for minimizing
adverse environmental impacts of each facility that seeks a permit renewal, the rule requires that facilities conduct a wide range
of studies related to impingement mortality and entrainment and submit the results with their permit applications.
In September 2014, several environmental non-governmental groups and certain energy industry groups filed petitions for

review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act. The cases were subsequently consolidated at the Second Circuit and a decision is expected by mid-2017.

In June 2016, the NJDEP issued a final NJPDES permit for Salem with an effective date of August 1, 2016. The final permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the Clean Water Act, it requires additional studies and the selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final permit for Salem. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the Clean Water Act. Such service water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

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State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power’s ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intake structures and cooling systems.
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.
Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA’s Clean Water Act Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in 2017. See Note 3. Early Plant Retirements.
Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates. The receipt of permits to allow construction and operation of the new facility could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.
In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council issued an order to approve siting BH5. All major environmental permits have been obtained except for the New Source air permit that is currently in draft form for public comment. Operations are expected to begin in mid-2019.
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 CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.
Jersey City, New Jersey Subsurface Feeder Cable Matter
In early October 2016, a discharge of mineral oil dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP has declared an emergency and an emergency response action has been undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, have issued multiple notices, orders and directives to the various parties related to this matter. The investigation and response actions related to the fluid discharge are ongoing. The investigation of the discharge and its potential cause is in the preliminary stages, making it difficult to determine the timing and potential costs to resolve this matter, as well as responsibility for such costs between PSE&G, Con Edison and NADC. Based on currently available information and the potential scope of the necessary repair and remediation work, the costs will likely be material. In addition, the timeline for completing the repairs has been extended due to the presence of debris within PSE&G’s easement. In November 2016, PSE&G filed an action in New Jersey Federal Court seeking an order requiring NADC to remove its debris from PSE&G’s easement so that PSE&G and Con Edison may comply with NJDEP and U.S. Coast Guard directives and complete the necessary repairs. NADC subsequently informed PSE&G that it would comply with the U.S. Coast Guard’s order and undertake debris removal activities so that PSE&G and Con Edison can complete the

necessary repairs. NADC’s debris removal activities are ongoing.

Steam Electric Effluent Guidelines

In September 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 Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.

Coal Combustion Residuals (CCRs)

On December 19, 2014, the EPA issued a final rule that 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, is residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy 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, 2017 is $276.83 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2017 of $335.33 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			
	2014	2015	2016	2017
36-Month Terms Ending	May 2017	May 2018	May 2019	May 2020 (A)
Load (MW)	2,800	2,900	2,800	2,800
$ per MWh	$97.39	$99.54	$96.38	$90.78

(A) Prices set in the 2017 BGS auction will become effective on June 1, 2017 when the 2014 BGS auction agreements expire.

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 24. 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 2018 and a significant portion through 2021 at Salem, Hope Creek and Peach Bottom.

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Power 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 beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations.
Power also has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.
As of December 31, 2016, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2021
	Millions
Nuclear Fuel	
Uranium	$ 301
Enrichment	$ 356
Fabrication	$ 192
Natural Gas	$ 1,029
Coal	$ 215

Regulatory Proceedings
FERC Compliance
PJM Bidding Matter
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 and self-reported the errors. As the internal 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 Power's peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future.
During the three month period 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. No additional charges to income have been recorded for this matter since that time.
Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into the matter and issued data requests covering a period from 2002 through the date of the self-report. This investigation is ongoing. Since that time, Power has responded to data requests from FERC Staff, including recent data requests in which Power has recalculated certain of its energy bids in PJM for a five year period, and may receive additional data requests or other fact finding. The FERC Staff investigation is still in the fact finding stage and there is considerable uncertainty around FERC's response to PSEG's legal arguments and the amount of disgorgement or other remedies FERC may ultimately seek.
PSEG is unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. These arguments include that Power's energy market bids in a substantial majority of the hours were below the allowed rate under the Tariff and therefore any errors in those hours were immaterial and that it is unclear whether the quantity of the bids violated any legal requirement. If PSEG's legal arguments do not prevail in whole or in part with FERC or in a judicial challenge that PSEG may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG's and Power's Consolidated

Statements of Operations in the quarterly and annual periods in which they are recorded.

Financial Transmission Rights (FTR) Auction Matter

In January 2017, ER&T received requests from the FERC Office of Enforcement relating to the planning and implementation of ER&T's participation in the annual FTR auction in PJM for the 2016-2017 planning year and the monthly FTR auctions in PJM for February, March and April 2016. PSEG is cooperating with FERC in this matter. PSEG cannot predict the outcome of this matter at this time.

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Nuclear Insurance Coverages and Assessments

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the property, decontamination and decommissioning liability insurance at the Salem/Hope Creek and Peach Bottom sites. NEIL also provides replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power's maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

Power is also a member of the joint underwriting association, American Nuclear Insurers (ANI), which provides nuclear liability insurance coverage at the Salem/Hope Creek and Peach Bottom sites. The ANI policies are designed to satisfy the financial protection requirements outlined in the Price-Anderson Act.

The ANI and NEIL policies all include coverage for claims arising out of acts of terrorism, however, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus such additional amounts as NEIL recovers for such losses from reinsurance, indemnity and any other source applicable to such losses.

The Price-Anderson Act sets the "limit of liability" for claims that could arise from an incident involving any licensed nuclear facility in the United States. The "limit of liability" is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The "limit of liability" per incident per site is comprised of a primary and excess layer. As of December 31, 2016, nuclear sites were required to purchase $375 million of primary liability coverage for each site (through ANI). This limit was increased to $450 million effective January 1, 2017.The primary layer is supplemented by an excess layer, which is an industry self-insurance pool. In the event a nuclear site has a claim that exceeds the primary layer, each licensee would be assessed a prorated share of the excess, up to $127 million per reactor, payable at not more than $19 million per reactor per incident per year. With 102 reactors currently in the insurance pool, the excess layer limit is $13.0 billion. If the damages exceed the "limit of liability," Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power's maximum aggregate assessment per incident is $401 million (based on Power's ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $60 million. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

Power's insurance coverages and maximum retrospective assessments for its nuclear operations as of December 31, 2016 were as follows:

Type and Source of Coverages	Site Coverage Millions		Retrospective Assessments
Public and Nuclear Worker Liability (Primary Layer):			
ANI	$375	(A)	$ —
Nuclear Liability (Excess Layer):			
Price-Anderson Act	12,986	(B)	401
Nuclear Liability Total	$13,361	(C)	$ 401
Property Damage (Primary Layer):			
NEIL Primary (Salem/Hope Creek)	$1,500		$ 35
NEIL Primary (Peach Bottom)	$1,500		14
Property Damage (Excess Layers):			
NEIL Excess (Salem/Hope Creek - Nuclear)	$300	(D)	2
NEIL Excess (Peach Bottom - Nuclear)	$300	(D)	1
NEIL Excess (Salem/Hope Creek - Non - Nuclear)	$300	(D)	1

NEIL Excess (Peach Bottom - Non - Nuclear)	$600	(D)	1
Accidental Outage - PSEG Share:(Nuclear / Non-Nuclear)			
NEIL I (Peach Bottom)	$245 / $164	(E)	8
NEIL I (Salem)	$281 / $188	(E)	9
NEIL I (Hope Creek)	$490 / $328	(E)	7
Nuclear Property Total			$ 78

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(A) The primary limit for Public Liability is a per site aggregate limit with no potential for retrospective assessment. The Nuclear Worker Liability represents the potential liability from third-party workers claiming exposure to the nuclear energy hazard. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion.

(B) Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the United States that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of September 10, 2013. The next adjustment is due on or before September 10, 2018. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

(C) Maximum limit of liability under the Price-Anderson Act for each nuclear incident per site.

(D) For nuclear event property limits in excess of $1.5 billion, Power purchases a $300 million Excess Policy for the Salem/Hope Creek site, and a $300 million Excess Policy only for Power’s 50% interest in Peach Bottom. This limit is not subject to reinstatement in the event of a loss. In addition, for non-nuclear event limits in excess of $1.5 billion, Power maintains a $300 million limit for the combined Salem/Hope Creek sites. Exelon maintains a $600 million non-nuclear event limit for Peach Bottom.

(E) Peach Bottom 2 and 3 have an aggregate nuclear indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Peach Bottom 2 and 3 have an aggregate non-nuclear indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 24 weeks. Salem 1 and 2 have an aggregate nuclear indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 76 weeks. Salem 1 and 2 have an aggregate non-nuclear indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 29 weeks. Hope Creek has an aggregate nuclear indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks. Hope Creek has an aggregate non-nuclear indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 26 weeks.

Minimum Lease Payments

The total future minimum payments under various operating leases as of December 31, 2016 are:

	PSE&G	Power	Services	Other	Total
	Millions				
2017	$12	$ 3	$ 13	$ 1	$29
2018	8	3	13	1	25
2019	7	3	13	1	24
2020	6	2	13	1	22
2021	6	2	14	1	23
Thereafter	61	39	132	—	232
Total Minimum Lease Payments	$100	$ 52	$ 198	$ 5	$355

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Note 14. Debt and Credit Facilities
Long-Term Debt

	Maturity	As of December 31, 2016	2015
		Millions	
PSEG			
Term Loan:			
Variable	2017	$500	$500
Total Term Loan		500	500
Senior Notes:			
1.60%	2019	400	—
2.00%	2021	300	—
Total Senior Notes		700	—
Principal Amount Outstanding		1,200	500
Fair Value of Swaps (A)		—	6
Amounts Due Within One Year		(500)	(6)
Net Unamortized Discount and Debt Issuance Costs		(5)	—
Total Long-Term Debt of PSEG		$695	$500

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	Maturity	As of December 31, 2016	2015
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (B):			
6.75%	2016	$—	$171
9.25%	2021	134	134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		149	320
Pollution Control Bonds (B):			
Floating Rate (C)	2033	—	50
Floating Rate (C)	2046	—	50
Total Pollution Control Bonds		—	100
Medium-Term Notes (MTNs) (B):			
5.30%	2018	400	400
2.30%	2018	350	350
1.80%	2019	250	250
2.00%	2019	250	250
7.04%	2020	9	9
3.50%	2020	250	250
1.90%	2021	300	—
2.38%	2023	500	500
3.75%	2024	250	250
3.15%	2024	250	250
3.05%	2024	250	250
3.00%	2025	350	350
2.25%	2026	425	—
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	450
3.65%	2042	350	350
3.80%	2043	400	400
4.00%	2044	250	250
4.05%	2045	250	250
4.15%	2045	250	250
3.80%	2046	550	—
Total MTNs		7,734	6,459
Principal Amount Outstanding		7,883	6,879
Amounts Due Within One Year		—	(171)
Net Unamortized Discount and Debt Issuance Costs		(65)	(58)
Total Long-Term Debt of PSE&G		$7,818	$6,650

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	Maturity	As of December 31, 2016	2015
		Millions	
Power			
Senior Notes:			
5.32%	2016	$—	$303
2.75%	2016	—	250
2.45%	2018	250	250
5.13%	2020	406	406
4.15%	2021	250	250
3.00%	2021	700	—
4.30%	2023	250	250
8.63%	2031	500	500
Total Senior Notes		2,356	2,209
Pollution Control Notes:			
Floating Rate (C)	2019	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,400	2,253
Amounts Due Within One Year		—	(553)
Net Unamortized Discount and Debt Issuance Costs		(18)	(16)
Total Long-Term Debt of Power		$2,382	$1,684

(A) PSEG entered into various interest rate swaps to hedge the fair value of certain debt at Power. The fair value adjustments from these hedges are reflected as offsets to long-term debt on the Consolidated Balance Sheets. For additional information, see Note 16. Financial Risk Management Activities.

(B) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

(C) The Pollution Control Financing Authority of Salem County bonds (Salem Bonds), which were repurchased and retired in 2016, and the Pennsylvania Economic Development Authority (PEDFA) bond that are serviced and secured by PSE&G Pollution Control Bonds and Power Pollution Control Notes, respectively, were variable rate bonds that were in weekly reset mode.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2016 are as

Year	PSEG	PSE&G	Power	Total
2017	$500	$—	$—	$500
2018	—	750	250	1,000
2019	400	500	44	944
2020	—	259	406	665
2021	300	434	950	1,684
Thereafter	—	5,940	750	6,690
Total	$1,200	$7,883	$2,400	$11,483

Long-Term Debt Financing Transactions

During 2016, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:
PSEG
- issued $400 million of 1.60% Senior Notes due November 2019, and

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- issued $300 million of 2.00% Senior Notes due November 2021

PSE&G

- issued $300 million of 1.90% Secured Medium-Term Notes, Series K due March 2021,
- issued $550 million of 3.80% Secured Medium-Term Notes, Series K due March 2046,
- issued $425 million of 2.25% Secured Medium-Term Notes, Series L due September 2026,
- retired $171 million of 6.75% Secured First and Refunding Mortgage Bonds Series VV at maturity, and
- repurchased at par $100 million of Salem Bonds and retired a like aggregate principal amount of its First and Refunding Mortgage Bonds which serviced and secured the Salem Bonds.

Power

- issued $700 million of 3.00% Senior Notes due June 2021,
- retired $303 million of 5.32% Senior Notes due September 2016, and
- retired $250 million of 2.75% Senior Notes due September 2016.

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 the $4.2 billion credit facilities are provided by a diverse bank group. As of December 31, 2016, the total available credit capacity was $3.5 billion.

As of December 31, 2016, no single institution represented more than 7% of the total commitments in the credit facilities.

As of December 31, 2016, the total credit capacity was in excess of the anticipated maximum liquidity requirements. Each of the 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.

The total credit facilities and available liquidity as of December 31, 2016 were as follows:

Company/Facility	As of December 31, 2016 Total Facility	Usage (D)	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facility	$500	$10	$ 490	Mar 2019	Commercial Paper Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	388	112	Apr 2020	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	$1,000	$398	$ 602		
PSE&G					
5-year Credit Facility (B)	$600	$14	$ 586	Apr 2020	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	$600	$14	$ 586		
Power					
5-year Credit Facility	$1,600	$195	$ 1,405	Mar 2019	Funding/Letters of Credit
5-year Credit Facility (C)	953	3	950	Apr 2020	Funding/Letters of Credit
Total Power	$2,553	$198	$ 2,355		
Total	$4,153	$610	$ 3,543		

(A) PSEG facility will be reduced by $12 million in March 2018.
(B) PSE&G facility will be reduced by $14 million in March 2018.

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(C) Power facility will be reduced by $24 million in March 2018.

(D) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs under which as of December 31, 2016, PSEG had $388 million outstanding at a weighted average interest rate of 1.03%. PSE&G had no amounts outstanding under its Commercial Paper Program as of December 31, 2016.

Fair Value of Debt

The estimated fair values, carrying amounts and methods used to determine fair value of long-term debt as of December 31, 2016 and 2015 are included in the following table and accompanying notes as of December 31, 2016 and 2015. See Note 17. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (A) (B)	$1,195	$1,185	$503	$506
PSE&G (B)	7,818	8,240	6,821	7,235
Power - Recourse Debt (B)	2,382	2,578	2,237	2,508
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	—	—	7	7
	$11,395	$12,003	$9,568	$10,256

(A) Fair value includes a $500 million floating rate term loan and net offsets. The fair value of the term loan debt (Level 2 measurement) was considered to be equal to the carrying value because the interest payments are based on LIBOR rates that are reset monthly. As of December 31, 2015, carrying amount includes such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

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

Note 15. Schedule of Consolidated Capital Stock

	As of December 31, Outstanding Shares		Book Value	
	2016	2015	2016	2015
			Millions	
PSEG Common Stock (no par value) (A)				
Authorized 1,000,000,000 shares	504,866,212	505,282,421	$4,219	$4,244

(A)

PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) or the Employee Stock Purchase Plan (ESPP) in 2016 or 2015. Total authorized and unissued shares of common stock available for issuance through PSEG's DRASPP, ESPP and various employee benefit plans amounted to approximately 7 million shares as of December 31, 2016.

As of December 31, 2016, PSE&G had an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

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Note 16. Financial Risk Management Activities

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 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. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power and PSE&G enter into additional contracts that are derivatives, but are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

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, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power’s expected generation. Changes in the fair market value of the derivative contracts are recorded in earnings.

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. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. Interest rate swaps totaling $550 million that converted Power’s Senior Notes due September 2016 into variable-rate debt matured in the third quarter of 2016. There were no outstanding interest rate swaps as of December 31, 2016. As of December 31, 2015, the fair value of all the underlying hedges was $6 million. The fair value hedges reduced interest expense by $6 million, $19 million and $20 million for the years ended December 31, 2016, 2015 and 2014, 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. As of December 31, 2016, PSEG had interest rate hedges outstanding totaling $500 million. These hedges were executed during the first quarter of 2016 and convert PSEG’s $500 million variable rate term loan due November 2017 into a fixed rate loan. The fair value of these hedges was $1 million and there was no ineffectiveness as of December 31, 2016. There were no outstanding interest rate hedges as of December 31, 2015.

PSEG executed forward starting swaps totaling $400 million during the first quarter of 2016 which were terminated upon the issuance of Power’s $700 million of 3.00% Senior Notes due June 2021. In the fourth quarter of 2016, PSEG executed $500 million of forward starting swaps which were terminated upon the issuance of PSEG’s $400 million of 1.6% Senior Notes due November 2019 and $300 million of 2.0% Senior Notes due November 2021. For additional information see Note 14. Debt and Credit Facilities.

The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was $2 million as of December 31, 2016 and immaterial as of December 31, 2015. The after-tax unrealized gains on these hedges expected to be reclassified to earnings during the next 12 months is $1 million.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the 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 PSEG's accounting policy, these positions are offset on the Consolidated Balance Sheets of Power and PSEG.

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

	As of December 31, 2016					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Cash Flow Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions					
Derivative Contracts						
Current Assets	$ 435	$(273)	$162	$ —	$ 1	$ 163
Noncurrent Assets	122	(98)	24	—	—	24
Total Mark-to-Market Derivative Assets	$ 557	$(371)	$186	$ —	$ 1	$ 187
Derivative Contracts						
Current Liabilities	$ (285)	$277	$(8)	$ (5)	$ —	$ (13)
Noncurrent Liabilities	(98)	95	(3)	—	—	(3)
Total Mark-to-Market Derivative (Liabilities)	$ (383)	$372	$(11)	$ (5)	$ —	$ (16)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$ 174	$1	$175	$ (5)	$ 1	$ 171

	As of December 31, 2015					
	Power (A)			PSE&G (A)	PSEG (A)	Consolidated
	Not Designated			Not Designated	Fair Value Hedges	
Balance Sheet Location	Energy-Related Contracts	Netting (B)	Total Power	Energy-Related Contracts	Interest Rate Swaps	Total Derivatives
	Millions					
Derivative Contracts						
Current Assets	$ 700	$(477)	$223	$ 13	$ 6	$ 242
Noncurrent Assets	208	(131)	77	—	—	77
Total Mark-to-Market Derivative Assets	$ 908	$(608)	$300	$ 13	$ 6	$ 319
Derivative Contracts						
Current Liabilities	$ (513)	$437	$(76)	$ —	$ —	$ (76)
Noncurrent Liabilities	(132)	116	(16)	(11)	—	(27)
Total Mark-to-Market Derivative (Liabilities)	$ (645)	$553	$(92)	$ (11)	$ —	$ (103)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$ 263	$(55)	$208	$ 2	$ 6	$ 216

(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 December 31, 2016 and 2015. 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 Consolidated Balance Sheets. As of December 31, 2016 and 2015, net cash collateral (received) paid of $1 million and $(55) million, respectively, were netted against the corresponding net

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derivative contract positions. Of the $1 million as of December 31, 2016, $(3) million was netted against noncurrent assets and $4 million was netted against current liabilities. Of the $(55) million as of December 31, 2015, cash collateral of $(53) million and $(16) million were netted against current assets and noncurrent assets, respectively, and $12 million and $2 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 by S&P or Moody’s, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody’s ratings. 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 $19 million and $78 million as of December 31, 2016 and 2015, respectively. As of December 31, 2016 and 2015, Power had the contractual right of offset of $9 million and $12 million, respectively, related to derivative instruments that are assets with the same counterparty under master 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 $10 million and $66 million as of December 31, 2016 and 2015, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the years ended December 31, 2016, 2015 and 2014.

	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)
Derivatives in Cash Flow Hedging Relationships	Years Ended December 31,		