PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-K
February 26, 2018
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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, 2017
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, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

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

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨
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, 2017 was $21,673,743,255 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 16, 2018 was 504,764,707.
As of February 16, 2018, 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 Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2018 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 12, 2018, 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 recover the carrying amount of our long-lived assets and leveraged leases;
- 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 194.

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 power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets.
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 invests in solar generation projects and regulated energy efficiency and related	Also earns revenues from solar generation facilities under long-term sales contracts for power and environmental products.

programs in New Jersey.

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Our other direct wholly owned subsidiaries are: PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under a contractual agreement; PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; 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 planned capital spend of $3.8 billion for transmission in 2018-2020 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. In January 2018, we filed a distribution base rate case requesting an adjustment in electric and gas base delivery rates that, if approved by the BPU, would increase overall revenues by approximately one percent. PSE&G anticipates that new base rates will take effect in the fourth quarter of 2018. 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 2017:

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	% of 2017 Sales	
Customer Type	Electric	Gas
Commercial	58%	37%
Residential	32%	59%
Industrial	10%	4%
Total	100%	100%

While our customer base has modestly increased since 2013, electric load has declined and gas load has increased as illustrated below:

Electric and Gas Distribution Statistics

	December 31, 2017				
	Number of Customers		Electric Sales and Gas Firm Sales (A)		Historical Annual Load Growth 2013-2017
Electric	2.2	Million	40,740	Gigawatt hours (GWh)	(0.4)%
Gas	1.8	Million	2,397	Million Therms	2.8%

(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 customer response to continued low gas prices. Only gas firm sales impact margin.

PSE&G, as part of its BPU-approved 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 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 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 continues 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 expect to 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.

In July 2017, we filed a petition with the BPU for a GSMP II program, an extension of our GSMP through which PSE&G has proposed investing $2.7 billion over five years beginning in 2019 to continue to modernize our gas system. For additional information, see Regulatory Issues.

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.

Supply

Although commodity revenues make up almost 38% 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 2017 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. In 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 414 MW direct current (dc) of PV solar generation facilities. Power also 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 (10,562 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, including projects currently under construction:

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•Generation Capacity

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels. As of December 31, 2017, our fuel mix was comprised of 47% gas, 35% nuclear, 11% coal, 5% oil and 2% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2017 was approximately 51,100 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 2017.

Generation by Fuel Type (A)	Actual 2017	
Nuclear:		
New Jersey facilities	41%	
Pennsylvania facilities	21%	
Fossil:		
Coal:		
Pennsylvania facilities	11%	
Connecticut facilities	—%	(B)
Natural Gas and Oil:		
New Jersey facilities	17%	
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 2.5 percent of total generation.

(B) Less than one percent.

We are also executing the following growth projects which are included in the 2018-2020 planned capital spend of $520 million for Fossil Growth Opportunities disclosed in Item 7. MD&A—Capital Requirements.

Major Growth Projects
As of December 31, 2017

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 (56 MW)	New York	2019	(A)
Bergen dual-fueled combined cycle uprate (32 MW)	New Jersey	2020	

(A) Two-thirds of the project is complete and operational.

•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 2017, our base load capacity factors were as follows:

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Unit	2017 Capacity Factor
Nuclear	
Salem Unit 1	89.0%
Salem Unit 2	84.9%
Hope Creek	100.0%
Peach Bottom Unit 2	99.2%
Peach Bottom Unit 3	91.4%
Coal	
Keystone	79.4%
Conemaugh	75.7%

- 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 2017 they accounted for approximately 86% 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 2020 and a significant portion through 2022.

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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 have coal inventory at the Bridgeport Station as well as off-site storage to meet the plant's projected requirements.

- 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 2019. 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 and a discussion of risks, see Item 1A. Risk Factors, Item 7. MD&A—Executive Overview of 2017 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 65 million people, nearly 20% 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 produced in adjacent states (e.g. Pennsylvania). This trend has reduced margin on forward sales as we re-contract our expected generation output.

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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 2017 to May 2018	$177
June 2018 to May 2019	$215
June 2019 to May 2020	$116
June 2020 to May 2021	$174

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.

We have obtained price certainty for our PJM capacity through May 2021 and New England capacity through May 2022 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.

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.

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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)	2015-2018	2016-2019	2017-2020	2018-2021
PSE&G	$99.54	$96.38	$90.78	$91.77
Jersey Central Power & Light Company (JCP&L)	$80.42	$74.85	$69.08	$73.11
Atlantic City Electric Company	$86.06	$82.14	$75.49	$81.23
Rockland Electric Company	$90.66	$85.02	$80.50	$85.94

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.
Power is developing a retail energy business to sell energy directly to commercial and industrial customers. We believe a retail energy platform complements our existing wholesale generation-to-load marketing business that is intended to hedge our generation assets. Power began these marketing activities in 2017 and has been granted retail energy supplier licenses in New Jersey, Pennsylvania and Maryland.
As of February 8, 2018, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2020.

Base Load Generation	2018	2019	2020
Generation Sales	100%	95%-100%	50%-55%

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 2020 and a significant portion through 2022. In March 2017, Westinghouse Electric Company (WEC) announced that it had filed for Chapter 11 bankruptcy in New York. WEC provides nuclear fuel

fabrication services for Salem Units 1 and 2. In January 2018, Brookfield Business Partners LP announced its intention to acquire WEC. The acquisition is expected to close in 2018 if it receives the required approvals from the regulators and bankruptcy courts. No assurances can be given that the acquisition will be approved. In the event that WEC is unable to continue to provide fabrication services, we can provide no assurance that Power would be able to find alternative providers of such services in a timely manner or on acceptable terms. A failure by WEC to perform its obligations during the pendency of, or following its emergence from, bankruptcy could have a material adverse impact on our business, the financial results of specific plants and on our results of operations.

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We also have various long-term fuel purchase commitments for coal to support our Keystone and Conemaugh 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.

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 2018 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’ $565 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2017, the counterparties for 59% 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 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, since January 2015, Power provides fuel procurement and power management services to LIPA under separate agreements.

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COMPETITIVE ENVIRONMENT

PSE&G

Our T&D 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 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 transacting in the wholesale energy markets, entering into bilateral contracts and selling to individual and aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers and retailers,
- private equity firms, banks 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 could have significant economic, environmental and reliability consequences. 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.

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While it is our expectation that continued efforts may be undertaken by the federal and state governments to preserve the existing base of fossil and nuclear 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.

EMPLOYEE RELATIONS

As of December 31, 2017, we had 12,945 employees within our subsidiaries, including 7,999 covered under collective bargaining agreements with eight unions expiring from 2019 through 2022. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2017

	PSE&G	Power	PSEG LI	Services
Non-Union	1,959	1,118	881	988
Union	5,209	1,293	1,486	11
Total Employees	7,168	2,411	2,367	999

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.

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

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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 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 Energy Resources & Trade (ER&T), PSEG Fossil, PSEG Nuclear, PSEG Power Connecticut, PSEG New Haven, PSEG Energy Solutions, PSEG Keys Energy Center LLC, 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 November 2017, FERC issued an order accepting the triennial filing made by the PSEG companies seeking authority to sell energy, capacity and ancillary services at market-based rates.

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 provide an opportunity for bonus payments or require the payment of penalties depending on whether a unit is available during a performance hour.

FERC has also 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 regarding operator actions affecting energy market prices and would promote better alignment between generation dispatch decisions and energy market price outcomes. We cannot predict what actions FERC might ultimately take, but such an examination could lead to future rule changes.

In June 2017, PJM issued an energy price formation proposal to address a flaw in the energy market in which energy prices during off-peak periods often do not reflect the production costs of generators during these periods even though they are serving load. PJM’s proposal would allow large, inflexible units to set price. If placed into effect, this proposal will improve price formation by ensuring that the marginal costs of units serving load will be better reflected in clearing prices. We cannot predict the outcome of this matter.

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. Various forums are considering how the competitive market framework can incorporate or be reconciled with state public policies that support particular resources, resource attributes or emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. We cannot predict what action, if any, FERC might take with regard to capacity market designs.

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 with enhanced incentives for performance during emergency conditions and significant penalties for non-performance, which was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. The

CP mechanism is intended to enhance the participation of intermittent and demand response resources (seasonal resources). Specifically, FERC approved PJM's modifications to the aggregation rules to improve the ability of seasonal resources to participate. However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions. We cannot predict the outcome of these matters.

PJM issued a series of white papers in response to public policies that seek to recognize value associated with generation plants beyond their cost effectiveness and reliability attributes. The three proposals are intended to spur stakeholder discussion and include both potential capacity and energy market reforms. The first energy market reform (see Energy Clearing Prices and

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Price Formation Initiatives) would allow inflexible generating units to set prices resulting in reduced uplift payments and improved price signals while the second energy market reform contemplates a voluntary carbon pricing program where states that elect to participate in the program would agree to put a price on carbon emissions. The capacity market proposal contemplates a two-stage capacity auction which, in its current form, would improve prices for unsubsidized resources, but would still continue to provide capacity payments for subsidized resources. The two-stage capacity market auction is now pending before the PJM stakeholders for consideration.

ISO-NE—ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and demand response. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. 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 due to the capacity market suppression associated with this mechanism is the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. Recently, ISO-NE submitted proposed changes to the FCM referred to as the Competitive Auctions and Sponsored Policy Resources (CASPR) proposal to accommodate clean and renewable energy policy resources. The CASPR design creates a second auction that commences immediately following the Forward Capacity Auction and provides the opportunity for certain renewable, clean and alternative energy resources to acquire supply obligations when they cannot clear economically in the Forward Capacity Auction. The CASPR design also proposed to phase out the 200 MW exemption from the minimum offer price rule (MOPR). We cannot predict the outcome of this proceeding.

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. In October 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.

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 an order instituting an investigation into the pricing of fast-start resources by three grid operators, PJM, NYISO and Southwest Power Pool. 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. PJM submitted a response to FERC's order that supported reforms to fast-start pricing with minor modifications. PJM also contended that all fast-start resource scheduled by PJM should be eligible to set locational marginal prices. We cannot predict the impact that these changes may have on our business.

Notice of Proposed Rulemaking (NOPR) on Baseload Generation

In September 2017, the Secretary of the U.S. Department of Energy (DOE) issued a NOPR to allow a full recovery of costs for certain eligible units physically located within the FERC-approved organized markets. In January 2018, FERC issued an order terminating the proceeding and initiating a new proceeding to explore resilience issues with the RTOs and ISOs. In the new proceeding, FERC is requiring each RTO and ISO to respond to a series of questions that appear to be intended to gain an

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understanding of the steps each RTO and ISO is taking to ensure the resilience of their respective grids. We expect to participate in this proceeding, but we are unable to predict the outcome.

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 2017, the 2018 Annual Formula Rate Update was filed with FERC and requested approximately $212 million in increased annual transmission revenues effective January 1, 2018, subject to true-up. In January 2018, PSE&G filed with FERC a revised 2018 Annual Transmission Formula Rate Update reducing the 2018 transmission annual revenue requirement to reflect the federal corporate income tax rate reduction from 35% to 21%, effective January 1, 2018, as provided in new comprehensive tax legislation enacted in December 2017 (Tax Act). This change in the federal corporate income tax rate reduces the annual revenue requirement by $148 million. 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. 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 February 2016 order, FERC reversed a previous order and accepted a filing by the PJM transmission owners seeking authority to assign costs for Regional Transmission Expansion Plan 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. FERC's orders have been challenged at the D.C. Circuit and PSE&G has intervened in support of FERC.

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.

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 March 2017, PJM staff made its final recommendation to the PJM Board with respect to the project. In April 2017, the PJM Board approved a portion of the project to PSE&G of the construction of necessary upgrade work at a cost of approximately $130 million. In October 2017, FERC accepted PJM's filing on the grounds that PJM correctly applied its Tariff. However, FERC deferred a ruling on whether the cost allocation methodology applied to the Artificial Island project is appropriate. FERC will decide this issue in a separate proceeding that is currently pending. We are unable to predict the outcome.

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. Although not named as a respondent, the complaint identifies PSE&G as one of the companies claimed to have been involved. In January 2018, a FERC administrative law judge issued an order generally finding that PJM and transmission owners, including PSE&G, did not engage in wrongful conduct. In addition, the developer's assertion of an entitlement to monetary damages was expressly denied. However, in a determination disputed by PSE&G, the order found that the PJM process lacked transparency. The judge's order will now be briefed by all parties for additional determinations by FERC.We are unable to predict the outcome of these proceedings.

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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. 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.

In February 2018, FERC issued an order finding that the transmission planning procedures used by the PJM transmission owners, a group that includes PSE&G, for supplemental projects do not adhere to the coordination and transparency principles of FERC's Order No. 890. FERC determined that certain terms and conditions in the PJM governing documents are unjust and unreasonable. FERC directed PJM and the PJM transmission owners to submit certain revisions to the manner in which the stakeholder process for supplemental projects is conducted. PSE&G will be participating in the PJM transmission owners' compliance filing.

Transmission Rate Proceedings—Numerous complaints have been filed at FERC in recent years seeking to reduce the base ROE of transmission owners across the country. Many of those complaints were resolved through agreement and settlement resulted in ROE reductions while others remain pending in the FERC adjudication process or are being litigated in the courts. Recent court decisions, as well as anticipated changes in the makeup at FERC, create some uncertainty as to the timing and outcome of these complaints. The results of these settlement and proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Con Edison Wheeling Agreement—Effective May 1, 2017, a wheeling arrangement which enabled Con Edison to move 1,000 MW of power from southeastern New York across the PSE&G system for delivery into New York City expired. Amounts that would have been recovered from Con Edison had this arrangement continued are now being recovered from other customers. PSE&G believes the current planning assumptions used by PJM are consistent with sound transmission planning principles. However, PSE&G disagrees with the absence of a mechanism to assign PJM transmission upgrade costs to Con Edison that reflect Con Edison's reliance on the PJM transmission grid. PSE&G and the BPU jointly filed a rehearing application at FERC seeking reversal of a determination not to create such a mechanism in connection with a PJM/NYISO joint operating agreement. In addition, in December 2017, the BPU filed a complaint at FERC against Con Edison and others petitioning FERC to create such a cost allocation mechanism that would assign PJM costs to New York.

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. 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 these 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.
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

The NRC conducts ongoing reviews of nuclear industry operating experience and may issue or revise regulatory requirements as a result of these ongoing reviews. 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 costs 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. In January 2018, PSE&G filed a distribution base rate case as required by the BPU as a condition of approval of PSE&G's Energy Strong Program. The filing requests $9.6 billion in rate base as of December 31, 2018, a 10.3% return on equity and a capitalization structure with a 54% equity component. The filing also requests an approximate one percent increase in revenues and seeks to recover investments made to strengthen electric and gas distribution systems. In its filing, PSE&G requested that these rates take into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in the Tax Act including a one-time credit for estimated excess income taxes collected between January 1, 2018 and the time new rates go into effect, and the flow-back to customers of certain additional tax benefits. PSE&G anticipates the new base rates will go into effect in the fourth quarter of 2018.

Separately, in January 2018, the BPU issued an order commencing a proceeding to ensure that the rate revenue resulting from expenses relating to taxes reflected in rates but no longer owed as the result of the Tax Act shall be passed onto the ratepayers. The BPU directed New Jersey utilities (including PSE&G) to make filings by March 2, 2018 setting forth interim rates to be effective April 1, 2018 reflecting the new federal corporate tax rate, and to subsequently file proposed final rates, effective July 1, 2018, incorporating all other effects of the Tax Act. This

proceeding is currently pending.
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 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.
Infrastructure Investment Program (IIP)—The BPU has enacted IIP regulations that allow utilities to construct, install or remediate utility plant and facilities related to reliability, resiliency and/or safety to support the provision of safe and adequate

service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety.

Gas System Modernization Program II (GSMP II)—In July 2017, we filed a petition with the BPU for a GSMP II program, an extension of GSMP to continue to modernize our gas system, through which PSE&G has proposed investing $2.7 billion over five years beginning in 2019. Under this proposed program, we plan to replace up to 1,250 miles of gas mains and associated service lines, with cost recovery at a 9.75% rate of return on equity through an accelerated recovery mechanism. This matter is pending. We believe the petition is consistent with the IIP regulations that the BPU approved in December 2017, as described above.

Energy Efficiency 2017 Program (EE 2017)—In August 2017, the BPU approved PSE&G's petition for EE 2017 to extend three existing energy efficiency subprograms (multi-family, direct install and hospital efficiency) and establish two new residential energy efficiency offerings. The two new offerings include deployment of smart thermostats and a pilot program to provide residential customers with energy usage information enabling them to reduce consumption. EE 2017, as approved, allows PSE&G to extend the subprogram offerings and establish the residential energy efficiency sub-programs under its existing energy efficiency clause recovery process. The EE 2017 allows for $69 million of additional investment and $16 million of additional administrative and information technology costs. The EE 2017 was added as the eleventh component of the Green Program Recovery Charges (GPRC) rate effective September 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. New Jersey utilities, including PSE&G, were required to be compliant with these requirements by October 1, 2017. We have submitted the required certification of compliance to the BPU.

In an effort to reduce the likelihood and severity of cyber incidents, we have a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of our company and our customers' information and our systems. In addition, we are subject to maintaining key cybersecurity controls to meet mandatory cybersecurity regulatory requirements. Our cybersecurity program is built on technical, procedural, and people-focused measures to detect, protect against, respond to, and recover from cyber threats to our systems and information including company, employee and customer data. Features of our program include: identifying critical information and systems; conducting cyber risk assessments of our and third party systems; maintaining awareness of cyber threats and vulnerabilities through partnerships with public and private entities, as well as industry groups; maintaining and testing our cybersecurity incident response plans and systems; training personnel on cybersecurity issues; and raising cybersecurity awareness throughout our company with electronic notices and seminars. We cannot assure that our cybersecurity program will be effective in preventing or mitigating cybersecurity incidents. For a discussion of the risks associated with cybersecurity threats, see Item 1A. Risk Factors.

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 distribution 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 action, this CTA policy will be applied only with respect to future distribution rate base cases, including our distribution base rate case filed in January 2018. In November 2014, the New Jersey Division of Rate Counsel appealed the BPU's decision and in September 2017, the New Jersey Superior Court, Appellate Division granted that appeal on procedural grounds. Upon remand, in January 2018, and updated in February 2018, the BPU issued a draft proposed rule that is pending review by the Office of Administrative Law. The draft proposal includes a 60-day comment period. We do not expect the application of a CTA to have a material impact on PSE&G's current earnings or its distribution base rate case filing.

Federal Tax Legislation —As a result of the enactment of the Tax Act, various state regulatory authorities, including the BPU, have taken action to ensure that excess federal income taxes previously collected in rates are returned to ratepayers. We have made filings to adjust the revenue requirement in certain of our rate matters as a result of the change in federal income tax rate.

We continue to assess whether any further action needs to be taken by the company at this time.

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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.

We expect there will be changes to existing environmental laws and regulations that 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) that 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. Circuit challenging the EPA’s Supplemental Finding. The D.C. Circuit is holding the case in abeyance pending further directions from the EPA. We do not expect this Supplemental Finding to impact operation of our facilities.

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 units, and (ii) natural gas combustion turbines. Simple cycle combustion turbines are exempt from the rule.

In October 2015, the EPA also 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 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.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the NSPS that establish emissions standards for CO_2 for certain new fossil power plants and the CPP. The D.C. Circuit granted the EPA's motion to hold the case in abeyance while the agency reviewed the rule. Upon completion of the review, the EPA Administrator signed a proposed repeal of the CPP. The EPA Administrator concluded that the CPP exceeds the EPA's statutory authority by considering measures that are beyond the control of the owners of the affected sources (fossil fuel-fired electric generating units). The EPA is considering rulemaking to replace the CPP. PSEG cannot assess the impact of any such rulemaking on our business and future results of operations at this time.

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. 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 September 2017, the RGGI States announced their new post-2020 program for a cap on regional CO_2 emissions, which would require a decline in CO_2 emissions in 2021 and each year thereafter, resulting in a 30% reduction in the CO_2 emissions cap by 2030.

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 New Jersey Department of Environmental Protection (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. In January 2018, New Jersey Governor Murphy signed an Executive Order requiring the NJDEP to initiate the rulemaking process for New Jersey to reenter RGGI. We cannot estimate the impact of this action on our business or results of operations at this time.

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 Limitation Guidelines Rule (ELG 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, and gasification wastewater. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

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 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, based on studies related to impingement mortality and entrainment and submit the results with their permit applications to be conducted by the facilities seeking renewal permits. Several environmental organizations and certain energy industry groups have filed suit under the CWA and the Endangered Species Act. The cases have been consolidated at the Second Circuit and a decision remains pending.

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 NJDEP issued the final New Jersey Pollutant Discharge Elimination System (NJPDES) permit for Salem. The final permit does not mandate specific service water system modifications but, consistent with Section 316(b) of the CWA, 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 NJPDES renewal permit for Salem. NJDEP has granted the hearing request, but it has not yet been scheduled. 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.

A permit application for renewal of the current NPDES permit for the Bridgeport Harbor Station Unit 3 (BH3) is under review by the Connecticut Department of Energy and Environmental Protection (CTDEEP). To address compliance with the EPA's CWA Section 316(b) final rule, we have proposed to 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 discussions with the CTDEEP, if the proposal is accepted, a final NPDES permit could be issued 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.

We have negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that we would retire BH3 early if all of its conditions precedent 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. 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 has commenced and operations are 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 modified Title V air permit.

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.

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 address injuries to natural resources 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.

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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. Under the Nuclear Waste Policy Act of 1982 (NWPA), nuclear plant owners are required to contribute to a Nuclear Waste Fund to pay for this service. Since May 2014, the DOE reduced the nuclear waste fee to zero. No assurances can be given that this fee will not be increased in the future. The NWPA allows spent nuclear fuel generated in any reactor to be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites.

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 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.

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, 2017	Office	Effective Date First Elected to Present Position
Ralph Izzo	60	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	54	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
David M. Daly	56	President and Chief Operating Officer (PSE&G)	October 2017 to present
		Chairman of the Board of PSEG Long Island LLC	October 2017 to present
		President and Chief Operating Officer (PSEG Long Island LLC)	October 2013 to October 2017
Ralph LaRossa	54	President and Chief Operating Officer (Power)	October 2017 to present
		President and Chief Operating Officer (PSE&G)	October 2006 to October 2017
		Chairman of the Board of PSEG Long Island LLC	October 2013 to October 2017
Derek M. DiRisio	53	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	53	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	55	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 have reduced our margins as nuclear and coal generation costs have not declined similarly.

PSEG and Power continue to monitor their remaining 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.

The decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production have been contributing factors to the significantly reduced revenues from nuclear generating stations while simultaneously raising the unit cost of production.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for enactment of proposed legislation in the state of New Jersey. We cannot predict whether the legislation will be enacted or, if enacted, whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

If market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. 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, environmental remediation costs and additional funding of the Nuclear Decommissioning Trust Fund (NDT) would be material to both PSEG and Power.

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 are 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 significantly 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.

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, coal

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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 pipeline 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 units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel raw material needs over the next several years. However, each of our nuclear units has contracted with a single fuel fabrication services provider, and transitioning to an alternative provider could take an extended period of time. Certain of our other generation facilities also require fuel or other services 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 our business, the financial results of specific plants and on our results of operations.

In March 2017, WEC announced that it had filed for Chapter 11 bankruptcy in New York. WEC provides nuclear fuel fabrication services for Salem Units 1 and 2. In January 2018, Brookfield Business Partners LP announced its intention to acquire WEC. The acquisition is expected to close in 2018 if it receives the required approvals from the regulators and bankruptcy courts. No assurances can be given that the acquisition will be approved. In the event that WEC is unable to continue to provide fabrication services, we can provide no assurance that Power would be able to find alternative providers of such services in a timely manner or on acceptable terms. A failure by WEC to perform its obligations during the pendency of, or following its emergence from, bankruptcy could have a material adverse impact on our business, the financial results of specific plants and on our results of operations.

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;

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- 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
- 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 have 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. Certain states, such as Massachusetts and California, are also considering mandating the use of power storage resources to replace uneconomic or retiring generation facilities. 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

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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 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. In January 2018, PSE&G filed a distribution base rate case proceeding. 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 its 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.

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. In particular, in January 2018, PSE&G filed a distribution base rate case proceeding. 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, manufactured gas plant (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.

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.

North American Electric Reliability Council (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.

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In November 2017, FERC issued an order accepting the triennial filing made by the PSEG companies seeking authority to sell energy, capacity and ancillary services at market-based rates.

Oversight by the Commodity Futures Trading Commission (CFTC) relating to derivative transactions—The CFTC has regulatory oversight of the swap and futures markets and options, 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.

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. 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.

Decommissioning—NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available to decommission the facility at the end of its useful life. PSEG Nuclear has established a Nuclear Decommissioning Trust (NDT) to satisfy these obligations. However, forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from

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current estimates. If we determine that it is necessary to retire one of our nuclear generating stations before the end of its useful life, there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT investments could appreciate in value. A shortfall could require PSEG to post parental guarantees or make additional cash contributions to ensure that the NDT continues to satisfy the NRC minimum funding requirements. As a result, our financial position or cash flows could be significantly adversely affected.

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. 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 capacity market design rules and ISO-NE’s forward capacity market rules continue to evolve, most recently in response to efforts to integrate public policy initiatives into the wholesale markets. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

We could also be impacted by a number of other events, including regulatory or legislative actions such as direct and indirect subsidies, favoring certain types of resources and/or technologies. 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 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, 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. While the EPA recently repealed these rules for existing power plants, actions by northeastern states, including New Jersey, could have cost implications for our fossil generation facilities. 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 has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. The rule requires that facilities seeking permit renewals conduct a wide range of studies

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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 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.

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.

In December 2017, the Tax Act was enacted, which made significant changes to U.S. tax law. Among other things, under the Tax Act, the statutory U.S. corporate income tax rate decreased from a maximum of 35% to 21%, effective January 1, 2018, and certain changes were made to bonus depreciation rules. However, the Tax Act is unclear in certain respects and will require interpretations and implementing regulations by the Internal Revenue Service (IRS), as well as state tax authorities, and the Tax Act could be subject to potential amendments and technical corrections. We cannot assess the impact that any such interpretations, regulations, amendments or corrections could have on our results of operations or financial condition. In addition, the regulatory treatment of certain impacts of the Tax Act will be subject to the discretion of FERC and the state regulators which we are unable to determine at this time.

We are subject to the provisions of the Financial Accounting Standards Board (FASB) Accounting Standards Codification 740, Income Taxes (ASC 740), which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. The impact of the rate change in 2017's financial statements is discussed in Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes.

We do not have the necessary information available, prepared, or analyzed (including computations) in reasonable detail to complete the accounting under ASC 740 for certain income tax effects of the Tax Act for the reporting period in which the Tax Act was enacted. Accordingly, the amounts recognized in the current reporting period should be considered provisional, in accordance with SEC Staff Accounting Bulletin No. 118, and any revisions to these amounts could be material.

Further, the Tax Act is unclear in certain respects and will require interpretations and implementing regulations by the Internal Revenue Service (IRS), as well as state tax authorities. The Tax Act could also be subject to potential amendments and technical corrections which could impact PSEG, PSE&G and Power's financial statements.

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.

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.

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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.
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 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

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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 long-lived 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%, 81% and 69% of the total assets of PSEG, PSE&G and Power, respectively, as of December 31, 2017. 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 2016, due to the adverse economic conditions experienced by coal generation in PJM, Energy Holdings recorded pre-tax write-downs relating to the NRG REMA, LLC (REMA) leveraged leases in the aggregate of $147 million. During 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain discussions with REMA management, Energy Holdings recorded additional pre-tax charges of $77 million in the aggregate.

In June 2017, GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. REMA was not included in the GenOn filing. Energy Holdings continues to monitor the restructuring of GenOn and its possible impacts on REMA and continues to discuss the situation with various parties relevant to this matter. 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.

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 recruitment and/or retention of key executives and a skilled workforce could adversely impact our businesses.

Our operations depend on the recruitment and 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. Certain events, such as the potential for early retirement of our nuclear facilities, can make it more difficult to retain these employees. 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, 2017, 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 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.

Cybersecurity threats to the U.S. energy market infrastructure are increasing in sophistication, magnitude and frequency. We rely on information technology systems that utilize sophisticated digital systems and network infrastructure to operate our generation, transmission and distribution systems. We also store sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers and vendors on our systems and conduct power marketing and hedging activities. In addition, the operation of our business is dependent upon the information technology systems of third parties, including our vendors, regulators, RTOs and Independent System Operators (ISOs), among others. Our and third-party information technology systems may be vulnerable to cybersecurity attacks involving domestic or foreign sources. A cybersecurity attack may also leverage such information technology to cause disruptions at a third party. Cybersecurity impacts to our operations include:

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- disruption of the operation of our assets and the power grid,
- theft of confidential company, employee, shareholder, vendor or customer information, which may cause us to be in breach of certain covenants and contractual obligations,
- 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.

In late 2017, PSE&G learned that its customers may be affected by a potential data breach involving the systems of TIO Networks, a subsidiary of PayPal Holdings. PayPal notified PSE&G that there was unauthorized access to TIO Networks' system that stores customer information. TIO Networks processed payments made at automated kiosks in PSE&G's walk-in customer service centers between 2012 and 2017. TIO Networks also facilitated payments PSE&G customers made at third-party payment centers, such as local convenience stores, that accept utility bill payments. The account numbers and addresses for PSE&G's approximately 2.5 million customers may have been exposed as a result of the suspected breach. Customers paying by check via kiosk at one of PSE&G's Customer Service Centers also may have had their personal checking account number and routing number exposed. We continue to work with TIO Networks and PayPal to analyze the impact of this event. While we have experienced and expect to continue to experience actual or attempted cyber-attacks on our information technology systems, none of these incidents has had a material impact on our operations or financial condition.

If a significant cybersecurity event or breach should occur within our company or with one of our material vendors, we could be exposed to significant loss of revenue, material repair costs to intellectual and physical property, significant fines and penalties for non-compliance with existing laws and regulations, significant litigation costs, increased costs to finance our businesses, reputational damage and loss of confidence from our customers, regulators, investors, vendors and employees. Similarly, a significant cybersecurity event or breach experienced by a competitor, regulatory authority, RTO, ISO, or vendor could also materially impact our business and results of operations via enhanced legal and regulatory requirements. For a discussion of state and federal cybersecurity regulatory requirements and information regarding our cybersecurity program, see Part 1, Item 1. Regulatory Issues.

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

None.

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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, 2017, 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:					
Sewaren	NJ	445	100%	445	Gas
Keystone (A)	PA	1,711	23%	391	Coal
Conemaugh (A)	PA	1,711	23%	385	Coal
Bridgeport Harbor	CT	383	100%	383	Coal
New Haven Harbor	CT	448	100%	448	Oil/Gas
Total Steam		4,698		2,052	
Nuclear:					
Hope Creek	NJ	1,180	100%	1,180	Nuclear
Salem 1 & 2	NJ	2,282	57%	1,310	Nuclear
Peach Bottom 2 & 3 (B)	PA	2,450	50%	1,225	Nuclear
Total Nuclear		5,912		3,715	
Combined Cycle:					
Bergen	NJ	1,229	100%	1,229	Gas/Oil
Linden	NJ	1,274	100%	1,274	Gas/Oil
Bethlehem	NY	790	100%	790	Gas
Kalaeloa	HI	208	50%	104	Oil
Total Combined Cycle		3,501		3,397	
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	130	100%	130	Gas/Oil
Bridgeport Harbor	CT	17	100%	17	Oil
Total Combustion Turbine		1,188		1,188	
Pumped Storage:					
Yards Creek (C)	NJ	420	50%	210	
Total Power Plants		15,719		10,562	

(A) Operated by GenOn Northeast Management Company.
(B) Operated by Exelon Generation.
(C) Operated by Jersey Central Power & Light Company.

As of December 31, 2017, Power also owned and operated 414 MW dc of photovoltaic solar generation facilities in various states.

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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, 2017, PSE&G’s electric transmission and distribution system included approximately 24,000 circuit miles, and 853,000 poles, of which 65% are jointly-owned. In addition, PSE&G owns and operates 50 switching stations with an aggregate installed capacity of 36,023 megavolt-amperes (MVA) and 244 substations with an aggregate installed capacity of 8,250 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, 2017, 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 58 natural gas metering and regulating stations, of which 22 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, 2017, PSE&G had 123 MW dc of installed solar capacity throughout New Jersey.

ITEM 3. LEGAL PROCEEDINGS
We are party to various lawsuits and environmental and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, see Item 1. Business—Regulatory Issues and Environmental Matters and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

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 16, 2018, there were 60,868 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2012 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.

	2012	2013	2014	2015	2016	2017
PSEG	$100.00	$109.35	$146.73	$142.46	$167.57	$204.11
S&P 500	$100.00	$132.31	$150.35	$152.47	$170.59	$207.74
DJ Utilities	$100.00	$112.67	$147.01	$142.57	$168.26	$190.76
S&P Electrics	$100.00	$113.20	$145.82	$138.80	$161.20	$180.76

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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
2017			
First Quarter	$46.14	$42.77	$ 0.43
Second Quarter	$45.94	$42.47	$ 0.43
Third Quarter	$47.47	$41.67	$ 0.43
Fourth Quarter	$53.28	$46.05	$ 0.43
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

On February 20, 2018, our Board of Directors approved a $0.45 per share common stock dividend for the first quarter of 2018. This reflects an indicative annual dividend rate of $1.80 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 2017 to satisfy obligations under various equity compensation award grants:

Three Months Ended December 31, 2017	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$ —
November 1-November 30	486,635	$ 49.86
December 1-December 31	—	$ —

In December 2017, we entered into a share repurchase plan that complies with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended, solely with respect to the repurchase of shares to satisfy obligations under equity compensation awards that are expected to vest or be exercised in 2018.
The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2017:

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	347,900	$ 33.49	13,771,542
Employee Stock Purchase Plan	—	—	3,174,168
Total	347,900	$ 33.49	16,945,710

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,	2017	2016	2015	2014	2013
	Millions, except Earnings per Share				
Operating Revenues (A)	$9,084	$9,061	$10,415	$10,886	$9,968
Income from Continuing Operations (B)(C)	$1,574	$887	$1,679	$1,518	$1,243
Net Income (B)(C)	$1,574	$887	$1,679	$1,518	$1,243
Earnings per Share:					
Income from Continuing Operations					
Basic	$3.12	$1.76	$3.32	$3.00	$2.46
Diluted	$3.10	$1.75	$3.30	$2.99	$2.45
Net Income					
Basic	$3.12	$1.76	$3.32	$3.00	$2.46
Diluted	$3.10	$1.75	$3.30	$2.99	$2.45
Dividends Declared per Share	$1.72	$1.64	$1.56	$1.48	$1.44
As of December 31,					
Total Assets	$42,716	$40,070	$37,535	$35,287	$32,480
Long-Term Obligations (D)	$12,071	$10,897	$8,837	$8,218	$7,830

(A) Operating Revenues for 2017, 2016 and 2015 includes $438 million, $410 million and $375 million, respectively, for Long Island Electric Utility Servco, LLC (Servco), a wholly owned subsidiary of PSEG LI. See Item 8. Financial Statements and Supplementary Data—Note 4. Variable Interest Entity for additional information.

(B) Income from Continuing Operations and Net Income for 2017 and 2016 includes after-tax expenses of $577 million and $396 million, respectively, related to the early retirement of Power’s Hudson and Mercer coal/gas generation plants and after-tax charges for 2017 and 2016 totaling $45 million and $92 million, respectively, related to investments in REMA’s leveraged leases 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 2017.

(C) Income from Continuing Operations and Net Income for 2017, include the non-cash net income benefit of $745 million, primarily resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017. See Item 8. Financial Statements and Supplementary Data—See Note 20. Income Taxes for additional information for 2017.

(D) 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 energy efficiency and related 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 and fuel supply functions through competitive energy sales in well-developed energy markets 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 are: 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); PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; 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 2017 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 2017 AND FUTURE OUTLOOK

2017 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, and
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

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Financial Results

The results for PSEG, PSE&G and Power for the years ended December 31, 2017 and 2016 are presented below:

	Years Ended December 31,	
	2017	2016
Earnings (Losses)	Millions, except per share data	
PSE&G	$973	$889
Power	479	18
Other	122	(20)
PSEG Net Income	$1,574	$887
PSEG Net Income Per Share (Diluted)	$3.10	$1.75

Our 2017 over 2016 increase in Net Income was due primarily to the favorable impacts of new tax legislation at Power and Energy Holdings in 2017, discussed below, partially offset by higher charges in 2017 related to the early retirement of our Hudson and Mercer units. Higher transmission revenues in 2017 at PSE&G, lower charges in 2017 related to investments in certain leveraged leases at Energy Holdings and lower plant outage costs at Power, partially offset by lower volumes of electricity sold at lower average prices, also contributed to the increase in Net Income. For a more detailed discussion of our financial results, see Results of Operations.

During 2017, 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 are 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. In July 2017, we filed a petition with the BPU for a GSMP II program, an extension of GSMP to continue to modernize our gas system, through which PSE&G has proposed investing $2.7 billion over five years beginning in 2019. This matter is pending. We believe the petition is consistent with the Infrastructure Investment Program (IIP) regulations that the BPU approved in December 2017. In August 2017, the BPU approved PSE&G’s petition for an Energy Efficiency 2017 Program (EE 2017) to extend three existing energy efficiency subprograms (multi-family, direct install and hospital efficiency) and establish two new residential energy efficiency offerings. The EE 2017 allows for $69 million of additional investment and $16 million of additional administrative and information technology costs. The EE 2017 was added as the eleventh component of the Green Program Recovery Charges (GPRC) rate effective September 1, 2017. 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 January 2018, PSE&G filed a distribution base rate case as required by the BPU as a condition of approval of its Energy Strong Program. The filing requests an approximate one percent increase in revenues and seeks to recover

investments made to strengthen electric and gas distribution systems. In its filing, PSE&G requested that these rates take into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in new tax legislation enacted in December 2017 (Tax Act), including a one-time credit for estimated excess income taxes collected between January 1, 2018 and the time new rates go into effect, and the flow-back to customers of certain additional tax benefits. PSE&G anticipates the new base rates will take effect in the fourth quarter of 2018.
Separately, in January 2018, the BPU issued an order commencing a proceeding to ensure that the rate revenue resulting from expenses relating to taxes reflected in rates but no longer owed as the result of the Tax Act shall be passed onto the ratepayers. The BPU directed New Jersey utilities (including PSE&G) to make filings by March 2, 2018 setting forth interim rates to be effective April 1, 2018, reflecting the new federal corporate tax rate, and to subsequently file proposed final rates, effective July 1, 2018, incorporating all other effects of the Tax Act. This proceeding is currently pending.

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As a result of the enactment of the Tax Act, various state regulatory authorities, including the BPU, have taken action to ensure that excess federal income taxes previously collected in rates are returned to ratepayers. We have made filings to adjust the revenue requirement in certain of our rate matters as a result of the change in federal income tax rate. We continue to assess whether any further action needs to be taken by the company at this time.

For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Power manages its existing firm pipeline transportation contracts for the benefit of PSE&G's customers through the basic gas supply service (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 may 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 2018 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 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 being at risk for early retirement. Most recently, in February 2018, Exelon, a co-owner of the Salem units, announced its intention to accelerate the closure of its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey's energy supply predominately by increasing New Jersey's reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market's vulnerability to price fluctuations and power disruptions in times of high demand. The New Jersey Legislature is assessing legislation that would provide a safety net in order to prevent the loss of environmental attributes from nuclear generating stations. We cannot predict whether the legislation will be enacted or, if enacted, whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey.

In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be influenced by the financial outlook of the units, including the progress, timing and continued outlook for enactment of proposed legislation in the state of New Jersey.

If market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. 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, environmental remediation costs and additional funding of the Nuclear Decommissioning Trust Fund (NDT) would be material to both PSEG and Power.

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.

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Transmission Planning

There are several matters pending before FERC and the U. S. Court of Appeals for the District of Columbia Circuit 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. 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 recovery, 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. 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. During 2015, PJM implemented a new "Capacity Performance" (CP) mechanism that created a more robust capacity product with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. The CP product was implemented fully in the May 2017 RPM auction for the 2020-2021 Delivery Year. Subsequent to its implementation, FERC approved changes to the CP construct that will enhance the participation of intermittent and demand response resources (seasonal resources). However, two complaints remain pending that ask FERC to investigate the rules governing the participation of seasonal resources and extend the participation of the base resources for future auctions.

In May 2017, PJM announced the results of the RPM capacity auction for the 2020-2021 Delivery Year. Power cleared approximately 7,800 MW of its generating capacity at an average price of $174 per MW-day for the 2020-2021 delivery period. In the two prior capacity auctions covering the 2019-2020 and 2018-2019 delivery years, Power cleared approximately 8,900 MW at an average price of $116 per MW-day and approximately 8,700 MW at an average price of $215 per MW-day, respectively. 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.

As a result of the efforts of certain entities in PJM to obtain financial support arrangements from their state commissions, 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.

In June 2017, PJM issued an energy price formation proposal to address a flaw in the energy market in which energy prices during off-peak periods often do not reflect the production costs of generators during these periods even though they are serving load. PJM's proposal would allow large, inflexible units to set price. If placed into effect, this proposal will improve price formation by ensuring that the marginal costs of units serving load will be better reflected in clearing prices. We cannot predict the outcome of this matter.

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

Distribution

The BPU has enacted IIP regulations that allow utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety.

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 requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the

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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.

In March 2017, the President of the United States issued an Executive Order that instructed the EPA to review the New Source Performance Standards that establish emissions standards for CO_2 for certain new fossil power plants, and the Clean Power Plan (CPP), a greenhouse gas emissions regulation under the Clean Air Act for existing power plants that establishes state-specific emission rate targets based on implementation of the best system of emission reduction. In October 2017, the EPA Administrator signed a proposed repeal of the CPP. The EPA Administrator concluded that the CPP exceeds the EPA's statutory authority by considering measures that are beyond the control of the owners of the affected sources (fossil fuel-fired electric generating units). The EPA is considering rulemaking to replace the CPP. PSEG cannot assess the impact of any such rulemaking on its business and future results of operations at this time.

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. While considerable uncertainty remains as to the final resolution of these matters, based upon developments in the investigation in the first quarter of 2017, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. PSEG is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power. We cannot predict the final outcome of these matters. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Early Retirement of Hudson and Mercer Units

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations. The decision to retire the Hudson and Mercer units had a material effect on PSEG's and Power's results of operations in 2016 and continued to adversely impact their results of operations in 2017. As of June 1, 2017, Power completed recognition of the incremental Depreciation and Amortization (D&A) of $938 million ($964 million in total) due to the significant shortening of the expected economic useful lives of Hudson and Mercer. During 2017, Energy Costs of $15 million and Operation and Maintenance (O&M) of $23 million were also incurred. See Item 8. Financial Statements and Supplementary Data—Note 3. Early Plant Retirements for additional information.

Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. 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.
In addition, PSEG and Power continue to monitor their other coal assets, including the 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 certain 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.

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Leveraged Lease Impairments

GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code on June 14, 2017. NRG REMA, LLC (REMA) was not included in the GenOn bankruptcy filing. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. PSEG cannot predict the outcome of GenOn's efforts to restructure its balance sheet and improve its liquidity.

During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss relating to its REMA leveraged lease receivables, which was reflected in Operating Revenues. During the second quarter of 2017, Energy Holdings recorded an additional $22 million pre-tax charge for its current best estimate of loss related to lease receivables due to collectability of payments ($15 million) and economics impacting the residual value ($7 million) of certain leased assets. 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 lease receivables, and continue to discuss the situation with various parties relevant to this matter. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 7. Long-Term Investments and Note 8. Financing Receivables. 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 Powerton generating facilities. Similar to Shawville, Joliet was recently converted to use natural gas. Converted natural gas units such as Shawville and Joliet may have higher operating costs and fuel consumption as well as longer start-up times compared to newer combined cycle gas units. Powerton is a coal-fired generating facility in Illinois. Each of these three 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 other less efficient natural gas and coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged lease receivables associated with these facilities.

Tax Legislation

In December 2017, the U.S. government enacted comprehensive tax legislation (Tax Act), which, among other things, decreased the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018, and made certain changes to bonus depreciation rules.

As a result of the enacted reduction in the statutory U.S. corporate income tax rate, as well as other aspects of the Tax Act, we have recorded a one-time, non-cash earnings benefit of $745 million, including $588 million related to Power and $147 million related to Energy Holdings. This benefit is primarily due to the remeasurement of deferred tax balances. In addition, PSE&G had excess deferred taxes of approximately $2.1 billion as of December 31, 2017 and recorded an approximate $2.9 billion revenue impact of these excess deferred taxes as Regulatory Liabilities where it is probable that refunds will be made to customers in future rates. The amount and timing of any such refund cannot be determined at this time.

Beginning in 2018, PSEG, on a consolidated basis, will incur lower income tax expense resulting in a decrease in its projected effective income tax rate. This is also expected to increase PSEG's and Power's net income. To the extent allowed under the Tax Act, Power's operating cash flows will reflect the full expensing of capital investments for income tax purposes. PSEG and Power expect that the interest on their debt will continue to be fully tax deductible albeit at a lower tax rate. For PSE&G, the Tax Act is expected to lead to lower customer rates due to lower income tax expense recoveries and the refund of deferred income tax regulatory liabilities, partially offset by the impacts of higher rate base. The impact of the lower federal income tax rate on PSE&G was reflected in PSE&G's recently filed distribution base rate case and its transmission formula rate filings. The Tax Act is generally expected to result in lower operating cash flows for PSE&G resulting from the elimination of bonus depreciation, partially offset by higher revenues due to the higher rate base. The full impact of these and other provisions of the Tax Act cannot be determined at this time.

The impact of the Tax Act may differ from these estimates, possibly materially, due to, among other things, changes in interpretations and assumptions PSEG has made, guidance that may be issued and actions PSEG may take as a result of the Tax Act. For additional information, see Note 20. Income Taxes.

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 2017, our

- diverse fuel mix and dispatch flexibility allowed us to generate approximately 51 terra-watt hours while addressing

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fuel availability and price volatility,

- total nuclear fleet achieved an average capacity factor of 94%, and
- utility was recognized for the sixteenth 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 2017 as we:

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2017 to $1.72 per share.

We expect to be able to fund our planned capital requirements, as described in Liquidity and Capital Resources, and manage the impacts of the Tax Act 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 2017, we

- made additional investments in transmission infrastructure projects,
- continued to execute our GSMP, Energy Strong, Energy Efficiency, solar and other existing BPU-approved utility programs,
- continued construction of our Keys and Sewaren 7 generation projects for targeted commercial operation in 2018 and commenced construction of our BH5 generation project for targeted commercial operation in mid-2019, and
- acquired six solar energy projects in various states totaling 88 MW-direct current (dc), for a total of 414 MW (dc) of installed capacity in 14 states throughout the U.S.

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, and obtain approval for extension of these programs,
- 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.

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For 2018 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 was filed with the BPU in January 2018,
- continuing discussions regarding the restructuring of GenOn and REMA and its potential impact on the value of our Keystone, Conemaugh and Shawville leveraged leases,
- the continuing impact of the Tax Act,
- 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 T&D 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,
- 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.

Power is developing a retail energy business to sell energy, which we believe complements our existing wholesale marketing business. Power began these marketing activities in 2017 and has been granted retail energy supplier licenses in New Jersey, Pennsylvania and Maryland.

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.

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RESULTS OF OPERATIONS

	Years Ended December 31,		
	2017	2016	2015
Earnings (Losses)	Millions		
PSE&G	$973	$889	$787
Power (A)(B)	479	18	856
Other (B)(C)	122	(20)	36
PSEG Net Income	$1,574	$887	$1,679
PSEG Net Income Per Share (Diluted)	$3.10	$1.75	$3.30

(A) Power's results in 2017 and 2016 include after-tax expenses of $577 million and $396 million, respectively, 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) Results in 2017 include the non-cash net income benefit of $745 million, including $588 million related to Power and $147 million related to Energy Holdings, resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017.

(C) 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 $45 million and $92 million related to its investments in REMA's leveraged leases in 2017 and 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 Nuclear Decommissioning Trust (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 Asset Retirement Obligation (ARO) is recorded in O&M Expense and the depreciation related to the ARO asset is recorded in D&A Expense.

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

The combined after-tax impact on Net Income for the years ended December 31, 2017, 2016 and 2015 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2017	2016	2015
	Millions, after tax		
NDT Fund and Related Activity (A)	$62	$—	$ 8
Non-Trading MTM Gains (Losses) (B)	$(99)	$(100)	$ 93

(A) Net of tax (expense) benefit of $(72) million, $(5) million and $(16) million for the years ended December 31, 2017, 2016 and 2015, respectively.

(B) Net of tax (expense) benefit of $68 million, $68 million and $(65) million for the years ended December 31, 2017, 2016 and 2015, respectively.

The 2017 year-over-year increase in our Net Income was driven primarily by:

- non-cash net income benefits related to new tax legislation (See Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes) at Power and Energy Holdings,
- higher transmission revenues,

- higher net NDT gains in 2017, and
- lower charges related to investments in certain leveraged leases at Energy Holdings (See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables).

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These increases were partially offset by:

- higher 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), and
- lower volumes of energy sold at lower average realized sales prices under the BGS contracts and in the PJM and New England regions.

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 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.

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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)	
	2017	2016	2015	2017 vs. 2016		2016 vs. 2015	
	Millions			Millions	%	Millions	%
Operating Revenues	$9,084	$9,061	$10,415	$23	—	$(1,354)	(13)
Energy Costs	2,800	3,001	3,261	(201)	(7)	(260)	(8)
Operation and Maintenance	2,869	3,008	2,978	(139)	(5)	30	1
Depreciation and Amortization	1,986	1,476	1,214	510	35	262	22
Income from Equity Method Investments	14	11	12	3	27	(1)	(8)
Other Income (Deductions)	228	124	152	104	84	(28)	(18)
Other-Than-Temporary Impairments	12	28	53	(16)	(57)	(25)	(47)
Interest Expense	391	385	393	6	2	(8)	(2)
Income Tax (Benefit) Expense	(306)	411	1,001	(717)	(174)	(590)	(59)

The 2017, 2016 and 2015 amounts in the preceding table for Operating Revenues and O&M costs each include $438 million, $410 million and $375 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 Entity for further explanation. The Income Tax Benefit in 2017 includes the non-cash benefit resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017. 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)	
	2017	2016	2015	2017 vs. 2016		2016 vs. 2015	
	Millions			Millions	%	Millions	%
Operating Revenues	$6,234	$6,221	$6,636	$13	—	$(415)	(6)
Energy Costs	2,363	2,567	2,722	(204)	(8)	(155)	(6)
Operation and Maintenance	1,434	1,475	1,560	(41)	(3)	(85)	(5)
Depreciation and Amortization	685	565	892	120	21	(327)	(37)
Other Income (Deductions)	87	79	75	8	10	4	5
Interest Expense	303	289	280	14	5	9	3
Income Tax Expense	563	515	470	48	9	45	10

Year Ended December 31, 2017 as compared to 2016

Operating Revenues increased $13 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $166 million due primarily to an increase in transmission revenues.

- Transmission revenues were $152 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.

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- Gas distribution revenues increased $30 million due to a $16 million increase due to Energy Strong, $10 million from inclusion of the GSMP in base rates, $4 million in higher collections of GPRC and an increase of $2 million due to higher sales volumes. These increases were partially offset by lower Weather Normalization Clause (WNC) revenues of $2 million.
- Electric distribution revenues decreased $16 million due primarily to a $28 million decrease in sales volume and $14 million in lower collections of GPRC, partially offset by a $26 million increase in Energy Strong revenues.

Clause Revenues increased $47 million due to the absence of the return in 2016 to customers of overcollections of Securitization Transition Charge (STC) revenues of $59 million and higher Margin Adjustment Clause (MAC) revenues of $4 million. These increases were partially offset by lower Societal Benefit Charges (SBC) of $17 million. The changes in STC, MAC and SBC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, D&A and Interest Expense. PSE&G does not earn margin on STC, SBC, Solar Pilot Recovery Charges (SPRC) or MAC collections.

Commodity Revenues decreased $204 million due to lower Electric revenues partially offset by higher Gas revenues. This decrease 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 $274 million due to $199 million in lower BGS revenues reflecting $109 million from lower sales volumes and $90 million from lower prices, $61 million in lower collections of Non-Utility Generation Charges (NGC) due primarily to lower prices and $14 million in lower revenues from the decreased sales volume of Non-Utility Generation (NUG) energy.
- Gas revenues increased $70 million due to higher BGSS prices of $68 million and $2 million from higher sales volumes.

Operating Expenses

Energy Costs decreased $204 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance decreased $41 million due to

- a $28 million net reduction related to various clause mechanisms and GPRC expenditures,
- a $15 million decrease in appliance service costs, and
- a $7 million net decrease in pension and OPEB expenses, net of amounts capitalized,
- partially offset by a $9 million net increase in other operating expenses.

Depreciation and Amortization increased $120 million due primarily to a $61 million net increase in amortization of Regulatory Assets, including the absence of the STC liability that ended in 2016, and an increase in depreciation of $59 million due to additional plant placed into service in 2017.

Other Income (Deductions) increased $8 million due primarily to a $7 million increase in Allowance for Funds Used During Construction (AFUDC).

Interest Expense increased $14 million primarily due to

- $11 million due to net long-term debt issuances in 2016 and $9 million due to net long-term debt issuances in 2017, partially offset by
- a decrease of $6 million due to clause-related interest for BGSS in 2016.

Income Tax Expense increased $48 million due primarily to higher pre-tax income.

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.
- Electric distribution revenues decreased $27 million due primarily to $47 million in lower collections of GPRC, partially offset by an $18 million increase in Energy Strong revenues.

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- 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 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 STC revenues of $419 million, lower SBC of $33 million and lower SPRC of $8 million. These decreases were partially offset by higher MAC revenues of $15 million. The changes in STC, SBC, SPRC and MAC amounts were entirely offset by changes in the amortization of related costs (Regulatory Assets) in O&M, D&A 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 NGC due primarily to lower prices, $42 million in lower revenues from the sale of NUG energy and $21 million in lower prices 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 T&D 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 to additional plant in 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 decrease 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.

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Power

	Years Ended December 31,			Increase / (Decrease) 2017 vs. 2016		Increase / (Decrease) 2016 vs. 2015	
	2017	2016	2015				
	Millions			Millions	%	Millions	%
Operating Revenues	$3,930	$4,023	$4,928	$(93)	(2)	$(905)	(18)
Energy Costs	1,983	1,986	2,150	(3)	N/A	(164)	(8)
Operation and Maintenance	1,038	1,143	1,057	(105)	(9)	86	8
Depreciation and Amortization	1,268	881	291	387	44	590	N/A
Income from Equity Method Investments	14	11	14	3	27	(3)	(21)
Other Income (Deductions)	157	45	97	112	N/A	(52)	(54)
Other-Than-Temporary Impairments	12	28	53	(16)	(57)	(25)	(47)
Interest Expense	50	84	121	(34)	(40)	(37)	(31)
Income Tax Expense (Benefit)	(729)	(61)	511	(668)	N/A	(572)	N/A

Year Ended December 31, 2017 as compared to 2016

Operating Revenues decreased $93 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $204 million due primarily to

- a decrease of $126 million in energy sales in the PJM and New England (NE) regions due primarily to lower average realized prices,
- a decrease of $100 million in electricity sold under our BGS contracts due primarily to lower volumes coupled with lower prices,
- a decrease of $24 million in revenue expected to be returned to ratepayers associated with excess federal income tax previously collected by Power’s subsidiary, PSEG New Haven LLC, due to the change in federal tax rates effective January 1, 2018,
- a decrease of $18 million in operating reserves in the PJM region,
- a charge of $10 million due to an increase in the FERC accrual related to the PJM bidding matter,
- a decrease of $7 million due to higher MTM losses in 2017 as compared to 2016. Of this amount, $120 million was due to increased forward prices, partially offset by a decrease of $113 million due to lower gains on positions reclassified to realized upon settlement in 2017 as compared to 2016,
- partially offset by a net increase of $53 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions,
- a net increase of $18 million in capacity revenues in the PJM and NE regions due to increases in cleared capacity and capacity auction prices, and
- an increase of $11 million due to higher sales related to new solar projects.

Gas Supply Revenues increased $110 million due primarily to

- an increase of $67 million in sales under the BGSS contract, of which $40 million was due to higher average sales prices coupled with a $27 million increase in sales volumes due to periods of colder weather in the heating season,
- a net increase of $24 million due to higher MTM gains in 2017 as compared to 2016, and
- an increase of $19 million related to sales to third parties, of which $48 million was due to higher average sales prices, partially offset by $29 million of lower volumes sold.

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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 $3 million due to

Generation costs decreased $69 million due primarily to

- a net decrease of $83 million primarily due to lower congestion costs in PJM due to lower rates coupled with less volumes, partially offset by higher transmission charges due to higher rates,
- a net decrease of $50 million due to charges associated with the announced early retirement of the Mercer and Hudson units in 2016, primarily related to lower coal inventory write-downs in 2017, partially offset by additional retirement costs incurred in 2017,
- partially offset by higher fuel costs of $31 million reflecting higher average realized prices for natural gas coupled with the utilization of higher volumes of coal, partially offset by the utilization of lower volumes of gas,
- an increase of $17 million due to MTM losses in 2017 as compared to MTM gains in 2016, and
- a net increase of $16 million primarily due to an increase in the volume of energy purchases in the NE region to serve load obligations.

Gas costs increased $66 million due to

- an increase of $50 million related to sales under the BGSS contract, of which $31 million was due to higher average gas costs, coupled with a $19 million increase in volumes sold due to periods of colder weather in the heating season, and
- an increase of $16 million related to sales to third parties, of which $44 million was due to higher average gas costs, partially offset by a $28 million decrease in volumes sold.

Operation and Maintenance decreased $105 million due to

- a $72 million decrease at our fossil plants, due primarily to the retirement of the Hudson and Mercer units and higher planned outage costs in 2016,
- a $35 million net decrease related to our nuclear plants due primarily to lower labor-related expenses and outage costs,
- an $8 million net decrease due to lower pension and OPEB costs,
- partially offset by $5 million of costs related to new solar plants placed into service in 2017.

Depreciation and Amortization increased $387 million due primarily to

- $346 million of higher depreciation for Hudson and Mercer, primarily due to the accelerated expense related to the early retirement of those units,
- a $15 million increase due to the accelerated retirement date for the Bridgeport Harbor unit 3,
- an $11 million increase due primarily to a higher nuclear asset base, and
- $11 million of higher depreciation due to new solar projects.

Other Income (Deductions) increased $112 million due primarily to higher net realized gains from the NDT Fund in 2017.

Other-Than-Temporary Impairments decreased $16 million due to lower impairments of equity securities in the NDT Fund in 2017.

Interest Expense decreased $34 million due primarily to

- a $24 million decrease due to higher interest capitalized for the construction of three new fossil stations: BH5, Sewaren 7 and Keys, and
- a net $7 million decrease due to debt maturities in September 2016, partially offset by a debt issuance in June 2016.

Income Tax Expense decreased $668 million due primarily to the one-time benefit recorded as a result of the remeasurement of deferred tax balances required due to the enactment of the Tax Act in December 2017.

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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 in 2016 compared to 2015. Also contributing to the decrease was $118 million of higher gains on positions reclassified to realized upon settlement in 2016 compared to 2015,
- 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 contract 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 2015 due to extremely cold weather, and
- 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.

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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.

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 revolving credit facility. PSE&G uses internally generated cash flow and its commercial paper program to meet seasonal, intra-month and temporary working capital needs. 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. PSEG LI's subsidiary, Long Island Electric Utility Servco, LLC (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 revolving credit facilities totaling $1.5 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 $700 million term loan credit agreement that is scheduled to expire in June 2019. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.1 billion of multi-year revolving 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, 2017, our operating cash flow decreased by $50 million. For the year ended December 31, 2016, our operating cash flow decreased by $608 million. The net changes were primarily due to net tax payments at PSEG and its other subsidiaries in 2017 offset by net changes from our subsidiaries as discussed below.

PSE&G

PSE&G’s operating cash flow decreased $55 million from $1,894 million to $1,839 million for the year ended December 31, 2017, as compared to 2016, due primarily to lower tax refunds and a decrease of $50 million related to a change in regulatory deferrals. These amounts were partially offset by higher earnings and $30 million in decreased vendor payments.

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.

Power

Power’s operating cash flow increased $71 million from $1,255 million to $1,326 million for the year ended December 31, 2017, as compared to 2016, primarily resulting from a decrease of $61 million in payments to counterparties, a $26 million increase from higher net collections of counterparty receivables, and higher earnings. These amounts were partially offset by higher tax payments and an increase in margin deposit requirements of $14 million.

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.

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, 2017 were as follows:

Company/Facility	As of December 31, 2017		
	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$1,500	$ 556	$ 944
PSE&G	600	15	585
Power	2,100	151	1,949
Total	$4,200	$ 722	$ 3,478

As of December 31, 2017, 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 $848 million and $783 million as of December 31, 2017 and 2016, respectively. The early retirement of Power’s Hudson and Mercer coal/gas generation units did not 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

PSE&G has $400 million of 5.30% Medium Term Notes maturing in May 2018 and $350 million of 2.30% Medium Term Notes maturing in September 2018.

Power has $250 million of 2.45% Senior Notes maturing in November 2018.

For a discussion of our long-term debt transactions during 2017 and into 2018, 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, 2017, PSE&G's Mortgage coverage ratio was 5.2 to 1 and the Mortgage would permit up to approximately $6.9 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.

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.

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Common Stock Dividends

Dividend Payments on Common Stock	Years Ended December 31, 2017	2016	2015
Per Share	$1.72	$1.64	$1.56
in Millions	$870	$830	$789

On February 20, 2018, our Board of Directors approved a $0.45 per share of common stock dividend for the first quarter of 2018. This reflects an indicative annual dividend rate of $1.80 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—Note16. 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 April 2017, S&P published updated research and affirmed the ratings and outlooks on PSEG and PSE&G. In June 2017, S&P published updated research on Power and the rating and outlook remained unchanged. In July 2017, Moody’s upgraded PSEG’s senior unsecured rating to Baa1 from Baa2 and revised its outlook to Stable from Positive. Also in July, Moody’s affirmed the ratings at PSE&G and Power.

	Moody’s (A)	S&P (B)
PSEG		
Outlook	Stable	Stable
Senior Notes	Baa1	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, 2017, we had Other Comprehensive Income of $34 million on a consolidated basis. Other Comprehensive Income was due primarily to a $44 million increase in net unrealized gains related to Available-for-Sale Securities, partially offset by a decrease of $8 million in our consolidated liability for pension and postretirement benefits and $2 million of unrealized losses on derivative contracts accounted for as hedges. 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.

	2018	2019	2020
		Millions	
PSE&G:			
Transmission	$1,235	$ 1,290	$1,280
Distribution	1,015	715	705
Energy Strong	35	—	—
Gas System Modernization Program	300	40	—
Solar/Energy Efficiency	85	75	55
Total PSE&G	$2,670	$ 2,120	$2,040
Power:			
Baseline	$170	$ 165	$165
Fossil Growth Opportunities	445	65	10
Other	30	30	20
Total Power	$645	$ 260	$195
Other	$40	$ 30	$20
Total PSEG	$3,355	$ 2,410	$2,255

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 November 2017, the BPU issued an order approving PSE&G's net investment of $100 million to rebuild New Jersey Transit's Mason electric distribution substation and related facilities in Kearny, New Jersey. This project is expected to be completed in December 2021.

In July 2017, PSE&G filed a petition with the BPU requesting approval of the $2.7 billion next phase of the Gas System Modernization Program (GSMP II) and associated cost recovery mechanism. The GSMP II program will enable PSE&G to continue to accelerate the replacement of its aging cast-iron and unprotected steel gas pipes. This matter is currently pending before the BPU and is not included in the PSE&G's projected capital expenditures above.

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In 2017, PSE&G made $2,919 million of capital expenditures, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $107 million, which are included in operating cash flows.

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.
- Fossil Growth Opportunities—investments associated with new construction, including Keys, Sewaren 7 and BH5, and with upgrades to increase efficiency and output at combined cycle plants.
- Other—includes investments made in response to environmental, regulatory and legal mandates and other capital projects.

In 2017, Power made $1,040 million of capital expenditures, excluding $191 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.

	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	$2,100	$—	$1,100	$1,000	$—
PSE&G	8,658	750	759	434	6,715
Power	2,400	250	450	950	750
Interest on Recourse Debt					
PSEG	157	49	65	43	—
PSE&G	5,186	313	578	525	3,770
Power	821	113	202	129	377
Capital Lease Obligations					
Power	2	1	1	—	—
Operating Leases					
PSE&G	113	16	17	15	65
Power	58	5	9	6	38
Services	194	14	30	30	120
Other	6	1	2	2	1
Energy-Related Purchase Commitments					
Power	2,670	730	938	468	534
Total Contractual Cash Obligations	$22,365	$2,242	$4,151	$3,602	$12,370
Liability Payments for Uncertain Tax Positions					

PSEG	$69	$69	$—	$—	$—
PSE&G	35	35	—	—	—
Power	30	30	—	—	—

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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 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	2017	2016	2015
Discount Rate	3.73 %	4.29 %	4.54 %
Expected Rate of Return on Plan Assets	7.80 %	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.
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 a net periodic pension credit in 2018 of approximately $(36) million, or $(87) 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.
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 3.73% discount rate for 2018. Actual future pension expense/income and funding levels

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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.

Assumption	% Change	Impact on Pension Benefit Obligation as of December 31, 2017	Increase to Pension Expense in 2018	Increase to Pension Expense, net of Amounts Capitalized in 2018
		Millions		
Discount Rate	(1)%	$ 866	$ 46	$ 36
Expected Rate of Return on Plan Assets	(1)%	N/A	$ 57	$ 57

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.

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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.

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 per the original lease terms, net of any subsequent impairments. 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.

A review of the residual valuations is 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 $78 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 with the corresponding expense recorded in Operation and Maintenance.

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.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power's nuclear facilities comprised 93% of Power's total AROs as of December 31, 2017. 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:

- financial feasibility and impacts on potential early shutdown,
- license renewals,
- 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 $120 million increase in the Nuclear ARO as of December 31, 2017. An increase of 1% in the inflation rate would result in a $324 million increase in the Nuclear ARO as of December 31, 2017. 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 $550 million at December 31, 2017. If Power were to increase its early shutdown probability to 100% and retire Salem and Hope Creek in 2021 (when the current capacity obligations for Salem and Hope Creek expire), which is significantly earlier than the end of their current license periods, the Nuclear ARO would increase by $428 million.

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

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Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

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

Commodity Contracts

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

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses. MTM VaR consists of MTM derivatives that are economic hedges. 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,	2017		2016	
95% Confidence Level, Loss could exceed VaR one day in 20 days				
Period End	$	39	$	26
Average for the Period	$	10	$	16
High	$	39	$	32
Low	$	5	$	10
99.5% Confidence Level, Loss could exceed VaR one day in 200 days				
Period End	$	60	$	40
Average for the Period	$	15	$	25
High	$	60	$	51

Low	$ 8	$ 16

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, 2017, a hypothetical 10% increase in market interest rates would result in

- $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $370 million decrease in the fair value of debt, including a $16 million decrease at PSEG, a $309 million decrease at PSE&G and a $45 million decrease at Power.

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Debt and Equity Securities

We have $6.3 billion of assets in a trust for our pension and OPEB plans. 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,
- 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, 2017, the portfolio included $1.1 billion of equity securities and $986 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, 2017, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $106 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 5.98 years and a yield of 2.72%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2017, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $59 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 $85 million, net of deferred taxes of $480 million, as of December 31, 2017. 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, and 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. 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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the “Company”) as of December 31, 2017 and 2016, 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, 2017, the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(a) (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2018

We have served as the Company's auditor since 1934.

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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

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the “Company”) as of December 31, 2017 and 2016, 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, 2017, and the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(b) (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.
Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2018

We have served as the Company's auditor since 1934.

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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

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2017 and 2016, 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, 2017, the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(c) (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.
Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2018

We have served as the Company's auditor since 2000.

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

	Years Ended December 31,		
	2017	2016	2015
OPERATING REVENUES	$9,084	$9,061	$10,415
OPERATING EXPENSES			
Energy Costs	2,800	3,001	3,261
Operation and Maintenance	2,869	3,008	2,978
Depreciation and Amortization	1,986	1,476	1,214
Total Operating Expenses	7,655	7,485	7,453
OPERATING INCOME	1,429	1,576	2,962
Income from Equity Method Investments	14	11	12
Other Income	319	191	254
Other Deductions	(91)	(67)	(102)
Other-Than-Temporary Impairments	(12)	(28)	(53)
Interest Expense	(391)	(385)	(393)
INCOME BEFORE INCOME TAXES	1,268	1,298	2,680
Income Tax Benefit (Expense)	306	(411)	(1,001)
NET INCOME	$1,574	$887	$1,679
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	505	505	505
DILUTED	507	508	508
NET INCOME PER SHARE:			
BASIC	$3.12	$1.76	$3.32
DILUTED	$3.10	$1.75	$3.30

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,		
	2017	2016	2015
NET INCOME	$1,574	$887	$1,679
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(37), $(41) and $34 for the years ended 2017, 2016 and 2015, respectively	44	42	(27)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $1, $(1), and $7 for the years ended 2017, 2016 and 2015, respectively	(2)	2	(10)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(4), $8 and $(18) for the years ended 2017, 2016 and 2015, respectively	(8)	(12)	25
Other Comprehensive Income (Loss), net of tax	34	32	(12)
COMPREHENSIVE INCOME	$1,608	$919	$1,667

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$313	$423
Accounts Receivable, net of allowances of $59 in 2017 and $68 in 2016	1,348	1,161
Tax Receivable	127	78
Unbilled Revenues	296	260
Fuel	289	326
Materials and Supplies, net	577	561
Prepayments	118	76
Derivative Contracts	29	163
Regulatory Assets	211	199
Other	4	7
Total Current Assets	3,312	3,254
PROPERTY, PLANT AND EQUIPMENT	41,231	39,337
Less: Accumulated Depreciation and Amortization	(9,434)	(10,051)
Net Property, Plant and Equipment	31,797	29,286
NONCURRENT ASSETS		
Regulatory Assets	3,222	3,319
Long-Term Investments	932	1,050
Nuclear Decommissioning Trust (NDT) Fund	2,133	1,859
Long-Term Tax Receivable	—	104
Long-Term Receivable of VIEs	686	589
Other Special Funds	231	217
Goodwill	16	16
Other Intangibles	114	98
Derivative Contracts	7	24
Other	266	254
Total Noncurrent Assets	7,607	7,530
TOTAL ASSETS	$42,716	$40,070

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2017	December 31, 2016
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$1,000	$500
Commercial Paper and Loans	542	388
Accounts Payable	1,694	1,459
Derivative Contracts	16	13
Accrued Interest	103	97
Accrued Taxes	48	31
Clean Energy Program	128	142
Obligation to Return Cash Collateral	129	132
Regulatory Liabilities	47	88
Other	461	426
Total Current Liabilities	4,168	3,276
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,240	8,658
Regulatory Liabilities	2,948	118
Asset Retirement Obligations	1,024	726
Other Postretirement Benefit (OPEB) Costs	1,455	1,324
OPEB Costs of Servco	542	452
Accrued Pension Costs	537	568
Accrued Pension Costs of Servco	129	128
Environmental Costs	357	401
Derivative Contracts	5	3
Long-Term Accrued Taxes	175	180
Other	221	211
Total Noncurrent Liabilities	12,633	12,769
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT	12,068	10,895
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2017 and 2016— 534 shares	4,961	4,936
Treasury Stock, at cost, 2017 and 2016—29 shares	(763)	(717)
Retained Earnings	9,878	9,174
Accumulated Other Comprehensive Loss	(229)	(263)
Total Stockholders' Equity	13,847	13,130
Total Capitalization	25,915	24,025
TOTAL LIABILITIES AND CAPITALIZATION	$42,716	$40,070

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,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$1,574	$887	$1,679
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,986	1,476	1,214
Amortization of Nuclear Fuel	199	203	213
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	103	109	104
Impairment Costs for Early Plant Retirements	—	102	—
Provision for Deferred Income Taxes (Other than Leases) and ITC	(167)	474	685
Non-Cash Employee Benefit Plan Costs	89	127	161
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(159)	(6)	26
Net (Gain) Loss on Lease Investments	48	92	—
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	188	183	(143)
Net Change in Regulatory Assets and Liabilities	(188)	(138)	(48)
Cost of Removal	(107)	(131)	(120)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(156)	(26)	(38)
Net Change in Certain Current Assets and Liabilities			
Tax Receivable	65	303	(94)
Accrued Taxes	16	3	(91)
Margin Deposit	(90)	(76)	122
Other Current Assets and Liabilities	(70)	(180)	288
Employee Benefit Plan Funding and Related Payments	(81)	(103)	(109)
Other	11	12	70
Net Cash Provided By (Used In) Operating Activities	3,261	3,311	3,919
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(4,190)	(4,199)	(3,863)
Purchase of Emissions Allowances and RECs	(117)	(99)	(106)
Proceeds from Sales of Available-for-Sale Securities	2,319	824	1,501
Investments in Available-for-Sale Securities	(2,340)	(856)	(1,552)
Other	72	82	78
Net Cash Provided By (Used In) Investing Activities	(4,256)	(4,248)	(3,942)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	154	24	364
Issuance of Long-Term Debt	2,175	2,675	1,350
Redemption of Long-Term Debt	(500)	(824)	(600)
Redemption of Securitization Debt	—	—	(259)
Cash Dividends Paid on Common Stock	(870)	(830)	(789)
Other	(74)	(79)	(51)
Net Cash Provided By (Used In) Financing Activities	885	966	15
Net Increase (Decrease) in Cash and Cash Equivalents	(110)	29	(8)
Cash and Cash Equivalents at Beginning of Period	423	394	402
Cash and Cash Equivalents at End of Period	$313	$423	$394

Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$(8)	$(245)	$447
Interest Paid, Net of Amounts Capitalized	$377	$365	$381
Accrued Property, Plant and Equipment Expenditures	$722	$664	$510

See Notes to Consolidated Financial Statements.

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

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
	Shs.	Amount	Shs.	Amount				
Balance as of January 1, 2015	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
Net Income	—	—	—	—	1,574	—	—	1,574
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(40)	—	—	—	—	—	34	—	34
Comprehensive Income								1,608
Cash Dividends on Common Stock	—	—	—	—	(870)	—	—	(870)
Other	—	25	—	(46)	—	—	—	(21)
Balance as of December 31, 2017	534	$4,961	(29)	$(763)	$9,878	$(229)	$—	$13,847

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,		
	2017	2016	2015
OPERATING REVENUES	$6,234	$6,221	$6,636
OPERATING EXPENSES			
Energy Costs	2,363	2,567	2,722
Operation and Maintenance	1,434	1,475	1,560
Depreciation and Amortization	685	565	892
Total Operating Expenses	4,482	4,607	5,174
OPERATING INCOME	1,752	1,614	1,462
Other Income	92	83	79
Other Deductions	(5)	(4)	(4)
Interest Expense	(303)	(289)	(280)
INCOME BEFORE INCOME TAXES	1,536	1,404	1,257
Income Tax Expense	(563)	(515)	(470)
NET INCOME	$973	$889	$787

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,		
	2017	2016	2015
NET INCOME	$973	$889	$787
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 2017, 2016 and 2015, respectively	(1)	—	(1)
COMPREHENSIVE INCOME	$972	$889	$786

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, 2017	December 31, 2016
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$242	$390
Accounts Receivable, net of allowances of $59 in 2017 and $68 in 2016	882	810
Accounts Receivable—Affiliated Companies	—	76
Unbilled Revenues	296	260
Materials and Supplies	197	180
Prepayments	44	9
Regulatory Assets	211	199
Other	4	6
Total Current Assets	1,876	1,930
PROPERTY, PLANT AND EQUIPMENT	29,117	26,347
Less: Accumulated Depreciation and Amortization	(6,101)	(5,760)
Net Property, Plant and Equipment	23,016	20,587
NONCURRENT ASSETS		
Regulatory Assets	3,222	3,319
Long-Term Investments	280	299
Other Special Funds	46	43
Other	114	110
Total Noncurrent Assets	3,662	3,771
TOTAL ASSETS	$28,554	$26,288

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, 2017	2016
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$750	$—
Accounts Payable	728	718
Accounts Payable—Affiliated Companies	340	260
Accrued Interest	78	76
Clean Energy Program	128	142
Derivative Contracts	—	5
Obligation to Return Cash Collateral	129	132
Regulatory Liabilities	47	88
Other	311	296
Total Current Liabilities	2,511	1,717
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,391	5,873
OPEB Costs	1,103	1,009
Accrued Pension Costs	226	250
Regulatory Liabilities	2,948	118
Environmental Costs	283	332
Asset Retirement Obligations	212	213
Long-Term Accrued Taxes	91	130
Other	114	116
Total Noncurrent Liabilities	8,368	8,041
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT	7,841	7,818
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2017 and 2016—132 shares	892	892
Contributed Capital	1,095	945
Basis Adjustment	986	986
Retained Earnings	6,861	5,888
Accumulated Other Comprehensive Income	—	1
Total Stockholder's Equity	9,834	8,712
Total Capitalization	17,675	16,530
TOTAL LIABILITIES AND CAPITALIZATION	$28,554	$26,288

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,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$973	$889	$787
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	685	565	892
Provision for Deferred Income Taxes and ITC	616	658	386
Non-Cash Employee Benefit Plan Costs	50	72	95
Cost of Removal	(107)	(131)	(120)
Net Change in Other Regulatory Assets and Liabilities	(188)	(138)	(48)
Net Change in Certain Current Assets and Liabilities			
Accounts Receivable and Unbilled Revenues	(106)	(84)	165
Materials and Supplies	(13)	(7)	(15)
Prepayments	(35)	22	11
Accounts Payable	1	(29)	45
Accounts Receivable/Payable—Affiliated Companies, net	101	199	—
Other Current Assets and Liabilities	17	8	(29)
Employee Benefit Plan Funding and Related Payments	(68)	(82)	(91)
Other	(87)	(48)	47
Net Cash Provided By (Used In) Operating Activities	1,839	1,894	2,125
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,919)	(2,816)	(2,692)
Proceeds from Sales of Available-for-Sale Securities	36	22	21
Investments in Available-for-Sale Securities	(37)	(24)	(22)
Solar Loan Investments	7	14	11
Other	10	15	11
Net Cash Provided By (Used In) Investing Activities	(2,903)	(2,789)	(2,671)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	—	(153)	153
Issuance of Long-Term Debt	775	1,275	850
Redemption of Long-Term Debt	—	(271)	(300)
Redemption of Securitization Debt	—	—	(259)
Contributed Capital	150	250	—
Other	(9)	(14)	(10)
Net Cash Provided By (Used In) Financing Activities	916	1,087	434
Net Increase (Decrease) in Cash and Cash Equivalents	(148)	192	(112)
Cash and Cash Equivalents at Beginning of Period	390	198	310
Cash and Cash Equivalents at End of Period	$242	$390	$198
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$(104)	$(295)	$(28)
Interest Paid, Net of Amounts Capitalized	$294	$273	$261
Accrued Property, Plant and Equipment Expenditures	$429	$420	$396

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, 2015	$ 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
Net Income	—	—	—	973	—	973
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	(1)	(1)
Comprehensive Income						972
Contributed Capital	—	150	—	—	—	150
Balance as of December 31, 2017	$ 892	$ 1,095	$ 986	$ 6,861	$ —	$ 9,834

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,		
	2017	2016	2015
OPERATING REVENUES	$3,930	$4,023	$4,928
OPERATING EXPENSES			
Energy Costs	1,983	1,986	2,150
Operation and Maintenance	1,038	1,143	1,057
Depreciation and Amortization	1,268	881	291
Total Operating Expenses	4,289	4,010	3,498
OPERATING INCOME (LOSS)	(359)	13	1,430
Income from Equity Method Investments	14	11	14
Other Income	213	102	169
Other Deductions	(56)	(57)	(72)
Other-Than-Temporary Impairments	(12)	(28)	(53)
Interest Expense	(50)	(84)	(121)
INCOME (LOSS) BEFORE INCOME TAXES	(250)	(43)	1,367
Income Tax Benefit (Expense)	729	61	(511)
NET INCOME	$479	$18	$856

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,		
	2017	2016	2015
NET INCOME	$479	$18	$856
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(39), $(41) and $32 for the years ended 2017, 2016 and 2015, respectively	46	42	(25)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $0, $0 and $7 for the years ended 2017, 2016 and 2015, respectively	—	—	(11)
Pension/OPEB adjustment, net of tax (expense) benefit of $(3), $9 and $(16) for the years ended 2017, 2016 and 2015, respectively	(7)	(13)	24
Other Comprehensive Income (Loss), net of tax	39	29	(12)
COMPREHENSIVE INCOME	$518	$47	$844

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, 2017	2016
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$32	$11
Accounts Receivable	380	276
Accounts Receivable—Affiliated Companies	221	205
Short-Term Loan to Affiliate	—	87
Fuel	289	326
Materials and Supplies, net	376	381
Derivative Contracts	29	162
Prepayments	11	10
Other	3	2
Total Current Assets	1,341	1,460
PROPERTY, PLANT AND EQUIPMENT	11,755	12,655
Less: Accumulated Depreciation and Amortization	(3,159)	(4,135)
Net Property, Plant and Equipment	8,596	8,520
NONCURRENT ASSETS		
NDT Fund	2,133	1,859
Long-Term Investments	87	102
Goodwill	16	16
Other Intangibles	114	98
Other Special Funds	57	53
Derivative Contracts	7	24
Other	67	61
Total Noncurrent Assets	2,481	2,213
TOTAL ASSETS	$12,418	$12,193

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, 2017	December 31, 2016
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$250	$—
Accounts Payable	712	539
Accounts Payable—Affiliated Companies	57	25
Short-Term Loan from Affiliate	281	—
Derivative Contracts	16	8
Accrued Interest	20	20
Other	99	88
Total Current Liabilities	1,435	680
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,406	2,170
Asset Retirement Obligations	810	511
OPEB Costs	283	251
Derivative Contracts	5	3
Accrued Pension Costs	184	191
Long-Term Accrued Taxes	52	77
Other	140	129
Total Noncurrent Liabilities	2,880	3,332
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT	2,136	2,382
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	4,911	4,782
Accumulated Other Comprehensive Loss	(172)	(211)
Total Member's Equity	5,967	5,799
TOTAL LIABILITIES AND MEMBER'S EQUITY	$12,418	$12,193

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,		
	2017	2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$479	$18	$856
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,268	881	291
Amortization of Nuclear Fuel	199	203	213
Provision for Deferred Income Taxes and ITC	(807)	(208)	261
Interest Accretion on Asset Retirement Obligation	30	26	26
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	188	183	(143)
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	103	109	104
Impairment Costs for Early Plant Retirements	—	102	—
Non-Cash Employee Benefit Plan Costs	28	39	48
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(156)	(26)	(38)
Net Change in Certain Current Assets and Liabilities			
Fuel, Materials and Supplies	42	31	62
Margin Deposit	(90)	(76)	122
Accounts Receivable	(45)	(71)	63
Accounts Payable	39	(22)	(46)
Accounts Receivable/Payable—Affiliated Companies, net	(2)	6	(84)
Other Current Assets and Liabilities	10	10	(36)
Employee Benefit Plan Funding and Related Payments	(7)	(13)	(11)
Other	47	63	18
Net Cash Provided By (Used In) Operating Activities	1,326	1,255	1,706
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,231)	(1,343)	(1,117)
Purchase of Emissions Allowances and RECs	(117)	(99)	(106)
Proceeds from Sales of Available-for-Sale Securities	2,182	739	1,422
Investments in Available-for-Sale Securities	(2,199)	(766)	(1,455)
Short-Term Loan—Affiliated Company	87	276	221
Other	46	46	34
Net Cash Provided By (Used In) Investing Activities	(1,232)	(1,147)	(1,001)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Long-Term Debt	—	700	—
Cash Dividend Paid	(350)	(250)	(400)
Redemption of Long-Term Debt	—	(553)	(300)
Short-Term Loan—Affiliated Company	281	—	—
Other	(4)	(6)	(2)
Net Cash Provided By (Used In) Financing Activities	(73)	(109)	(702)
Net Increase (Decrease) in Cash and Cash Equivalents	21	(1)	3
Cash and Cash Equivalents at Beginning of Period	11	12	9
Cash and Cash Equivalents at End of Period	$32	$11	$12
Supplemental Disclosure of Cash Flow Information:			

Income Taxes Paid (Received)	$77	$50	$393
Interest Paid, Net of Amounts Capitalized	$48	$81	$116
Accrued Property, Plant and Equipment Expenditures	$293	$244	$114

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, 2015	$ 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
Net Income	—	—	479	—	479
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(42)	—	—	—	39	39
Comprehensive Income					518
Cash Dividends Paid	—	—	(350)	—	(350)
Balance as of December 31, 2017	$ 2,214	$ (986)	$ 4,911	$ (172)	$ 5,967

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 energy efficiency and related 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 and fuel supply functions through competitive energy sales in well-developed energy markets 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 are: 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); PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; 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 Entity. 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 significant 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. 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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.

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 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.

Certain offsetting derivative assets and liabilities 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, these positions are offset on the Consolidated Balance Sheets of Power and PSEG.

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 Entity for further information.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The majority of Energy Holdings' revenues relate to its investments in leveraged leases. Income on leveraged leases is recognized by a method which produces a constant rate of return on the outstanding net investment in the lease, net of the related deferred tax liability, in the years in which the net investment is positive. Any gains or losses incurred as a result of a lease termination are recorded as revenues as these events occur in the ordinary course of business of managing the investment portfolio.

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:

	2017 Avg Rate		2016 Avg Rate		2015 Avg Rate	
Electric Transmission	2.41	%	2.39	%	2.42	%
Electric Distribution	2.51	%	2.49	%	2.50	%
Gas Distribution	1.63	%	1.63	%	1.64	%

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, 2017, 2016 and 2015 were as follows:

	AFUDC/IDC Capitalized								
	2017			2016			2015		
	Millions	Avg Rate		Millions	Avg Rate		Millions	Avg Rate	
PSE&G	$73	7.42	%	$66	7.81	%	$65	8.01	%
Power	$78	4.60	%	$54	4.87	%	$27	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.

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Impairment of Long-Lived Assets and Leveraged Leases

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).

Energy Holdings' leveraged leases are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. Residual values are the estimated values of the leased assets at the end of the respective lease per the original lease terms, net of any subsequent impairments. A review of the residual valuations, which are calculated by discounting the cash flows related to the leased assets after the lease term, is 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.

Cash and Cash Equivalents

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

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 initial 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, improve 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.

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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) 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 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 preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Note 2. Recent Accounting Standards

New Standards Issued and Adopted

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 consideration of 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 were able to adopt it for transactions that closed before the effective date but had not been reported in financial statements that had been issued or made available for issuance. PSEG adopted this standard in the third quarter 2017 with the acquisition of a solar project. This standard upon adoption had no impact on PSEG's financial statements.

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.

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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. PSEG adopted this standard on January 1, 2018. PSEG will elect the full retrospective method of transition. Under this method, PSEG will restate its prior period financial statements to align with the 2018 presentation.
PSEG has evaluated existing contracts and revenue streams for potential changes under the new revenue recognition standard. Included in the scope of the new standard are PSE&G’s regulated revenue recorded under tariffs, including the sale of default supply of electric and gas commodity, and the distribution of electricity and gas to retail residential and commercial and industrial customers, and transmission revenues. Tariff revenues comprise substantially all of PSE&G’s revenue. PSEG expects no material change in revenue recognition of PSE&G’s regulated revenue recorded under tariffs. PSE&G’s revenue from contracts with customers will continue to be recorded as electricity or gas is delivered to the customer. Certain reclassifications of PSE&G’s revenue streams will affect Operating Revenues and Operating Expenses due to the application of this standard.
Also included in the scope of the new standard are Power’s electricity, gas and related product sales. Certain reclassifications of Power’s revenue streams will also affect Operating Revenues and Energy Costs due to the application of this standard.
PSEG, PSE&G and Power do not anticipate any material impact to net income as a result of adoption of this new standard.
The new standard will result in more detailed disclosures of revenue compared to current guidance and changes in presentation. PSEG will disaggregate its revenues by operating segment. PSE&G will further disaggregate its revenue by product line (i.e. electric distribution, gas distribution, and transmission). Power will further disaggregate its revenues by product line (i.e. electricity, gas). Electricity revenues will be further disaggregated by region (i.e. PJM, New York ISO and ISO New England). Gas revenues will be further disaggregated by third party sales and sales to affiliates. Other Revenues from Contracts with Customers will also be disclosed including PSE&G appliance service and repair and Power solar power revenues.
PSEG will elect the invoice practical expedient, where applicable, in recording its revenue. Under the practical expedient, PSEG has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of PSEG’s performance completed to date. PSEG may recognize revenue in the amount to which it has a right to invoice. As such under this practical expedient, there are no future performance obligations to disclose. Where PSEG has entered into fixed consideration contracts, it will disclose its remaining performance obligations under these agreements.
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 recorded a cumulative effect adjustment by reclassifying the unrealized gain related to equity investments of $342 million ($176 million, net of tax) from Accumulated Other Comprehensive Income to Retained Earnings on January 1, 2018, and expects increased volatility in Net Income due to changes in fair value of its equity securities within the NDT and Rabbi Trust Funds.
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; early adoption was permitted. PSEG expects no changes in its presentation of its Statement of Cash Flows as a result of adopting this new standard. PSEG adopted this standard on January 1, 2018 using a retrospective transition method to each period presented.

Statement of Cash Flows: Restricted Cash

This accounting standard requires entities to explain the change during the period in the total of cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents, either in a narrative or a tabular format. Amounts generally described as restricted cash or restricted cash equivalents should be included in entities' 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; early adoption was permitted. PSEG adopted this standard on January 1, 2018 using a retrospective transition method for each period presented. PSEG will continue the current balance sheet classification of restricted cash or restricted cash equivalents. PSEG will provide a reconciliation of cash and cash equivalents and restricted cash or restricted cash equivalents and include a description of these amounts.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)

This accounting standard was issued to improve the presentation of net periodic pension cost and net periodic OPEB cost.

Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component will be eligible for capitalization, when applicable.

The standard requires the amendments to be applied retrospectively for the presentation of the service cost component and the other cost components of net periodic pension cost and net periodic OPEB cost in the Statement of Operations and prospectively, on and after the effective date, for the capitalization of the service cost component of net periodic pension and OPEB costs.

The standard is effective for annual and interim reporting periods beginning after December 15, 2017. PSEG adopted this standard as of January 1, 2018. Beginning January 1, 2018, PSEG and each of its subsidiaries began to classify the total net pension and OPEB non-service benefit costs in a separate line item in the Statement of Operations after Operating Income. PSEG will also recast those amounts for prior years in accordance with the new standard by using the practical expedient of using the previously disclosed non-service components of pension and OPEB costs. The service cost component of pension and OPEB costs will continue to be classified in O&M Expense, except for that portion capitalized, as appropriate, within Property, Plant and Equipment. As a result of adopting this new standard, PSE&G expects to reduce its charge to expense by approximately $55 million to $65 million in 2018.

Stock Compensation - Scope of Modification Accounting

This accounting standard provides clarity and reduces both diversity in practice and complexity when applying the stock compensation guidance to a change in the terms or conditions of a stock-based payment award. Specifically, the standard provides guidance as to which changes to the terms or conditions of a stock-based payment award require an entity to apply modification accounting.

The standard is effective for all entities for annual periods, and interim periods within those annual periods, beginning after December 15, 2017, early adoption was permitted. This standard should be applied prospectively to an award modified on or after the adoption date. PSEG adopted this standard effective January 1, 2018.

New Standards Issued But Not Yet Adopted

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.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities

This accounting standard's amendments more closely align hedge accounting with the companies' risk management activities in the financial statements. The amendments expand hedge accounting for both non-financial and financial risk components by permitting contractually specified components to designate as the hedged risk in a cash flow hedge involving the purchase or sale of non-financial assets or variable rate financial instruments. Additionally, the amendments ease the operational burden of applying hedge accounting by allowing more time to prepare hedge documentation, and allow effectiveness assessments to be performed on a qualitative basis after hedge inception.

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The new guidance is effective for annual and interim periods beginning after December 15, 2018. The standard requires using a modified retrospective method upon adoption. Early adoption is permitted. PSEG is currently analyzing the impact of this standard on its consolidated financial statements.

Premium Amortization on Purchased Callable Debt Securities

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date. The amendments do not require an accounting change for securities held at a discount; the discount continues to be amortized to maturity. The standard is effective for annual and interim reporting periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period. If an entity early adopts the standard in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period. An entity should apply this standard on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. Additionally, in the period of adoption, an entity should provide disclosures about a change in accounting principle. PSEG is currently analyzing the impact of this standard on its financial statements.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

This accounting standard would affect any entity that is required to apply the provisions of the Accounting Standards Codification topic, “Income Statement-Reporting Comprehensive Income,” and has items of other comprehensive income for which the related tax effects are presented in other comprehensive income as required by GAAP. Specifically, this standard would allow entities to record a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the newly enacted federal corporate income tax rate. The amount of the reclassification would be the difference between the historical corporate income tax rate and the newly enacted 21% corporate income tax rate.

The standard is effective for all entities for annual periods, and interim periods within those annual periods beginning after December 15, 2018. Early adoption is permitted for an entity in any interim or annual period for public business entities for reporting periods for which financial statements have not yet been issued or made available for issuance. An entity would be able to choose to apply this standard retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the new tax legislation enacted in 2017 is recognized or apply the standard in the reporting period adopted. PSEG is currently analyzing the impact this standard, if adopted, could have on its consolidated 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.

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.

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Note 3. Early Plant Retirements

Fossil

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. Both units were available to operate through May 31, 2017 and were subsequently retired from operation on June 1, 2017. As of December 31, 2017, the retirements of both units were substantially complete.

In the latter half of 2016, PSEG and Power recognized pre-tax charges in Energy Costs and 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 Depreciation and Amortization (D&A) during 2016 of $571 million due to the significant shortening of the expected economic useful lives of Hudson and Mercer.

As of June 1, 2017, Power recognized total D&A of $964 million for the Hudson and Mercer units to reflect the end of their economic useful lives in 2017. During the year ended December 31, 2017, Power recognized pre-tax charges in Energy Costs of $15 million, primarily for coal inventory lower of cost or market adjustments. During the year ended December 31, 2017, Power also recognized pre-tax charges in O&M of $23 million, including shut down costs and an increase in the Asset Retirement Obligation due to settlements and changes in cash flow estimates, partially offset by changes in employee-related severance costs. Power is exploring various opportunities with these sites, including using the sites for alternative industrial activity or the disposition of one or both of the sites. 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.

As of December 31, 2016, Power had reduced the estimated useful life of Bridgeport Harbor Station unit 3 (BH3) from 2025 to the summer of 2021 as it was more likely than not it will retire the unit by this time.

PSEG and Power continue to monitor their other coal assets, including the 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 certain 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 held for use classification of our remaining coal units may have a material adverse impact on PSEG’s and Power’s future financial results.

Nuclear

Since 2013, several nuclear generating stations in the United States have closed or announced early retirement due to economic reasons, or have announced being at risk for early retirement. Most recently, in February 2018, Exelon, a co-owner of the Salem units, announced its intention to accelerate the closure of its Oyster Creek nuclear plant located in New Jersey, one year earlier than previously planned for economic reasons. These closures and retirements are generally due to the decline in market prices of energy, resulting from low natural gas prices driven by the growth of shale gas production since 2007, the continuing cost of regulatory compliance and enhanced security for nuclear facilities, both federal and state-level policies that provide financial incentives to construct renewable energy such as wind and solar and the failure to adequately compensate nuclear generating stations for the attributes they bring similar to renewable energy production. These trends have significantly reduced the revenues of nuclear generating stations while limiting their ability to reduce the unit cost of production. This may result in the electric generation industry experiencing a further shift from nuclear generation to natural gas-fired generation, creating less diversity of the generation fleet.

If any or all of the Salem and Hope Creek units were shut down, it would significantly alter New Jersey’s energy supply predominately by increasing New Jersey’s reliance on natural gas generation. Such a decrease in fuel diversity could also increase the market’s vulnerability to price fluctuations and power disruptions in times of high demand. The

New Jersey Legislature is assessing legislation that would provide a safety net in order to prevent the loss of environmental attributes from nuclear generating stations. Power cannot predict whether the legislation will be enacted or, if enacted, whether our nuclear generating stations in New Jersey will be selected or whether the legislation will provide a sufficient safety net for the continued operation of nuclear generating stations in New Jersey. In the ordinary course, management, and in the case of the Salem units the co-owner, each makes a number of decisions that impact the operation of our nuclear units beyond the current year, including whether and to what extent these units participate in RPM capacity auctions, commitments relating to refueling outages and significant capital expenditures, and decisions regarding our hedging arrangements. When considering whether to make these future commitments, management's decisions will primarily be

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influenced by the financial outlook of the units, including the progress, timing and continued outlook for enactment of proposed legislation in the state of New Jersey.
If market prices continue to be depressed and legislation is not enacted that adequately compensates nuclear generating stations for their attributes, Power anticipates it will no longer be covering its costs nor be adequately compensated for its market and operational risks at the Salem and Hope Creek nuclear units and would anticipate retiring these units early. 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, environmental remediation costs and additional funding of the Nuclear Decommissioning Trust Fund (NDT) would be material to both PSEG and Power.
The following table provides the balance sheet amounts by generating station as of December 31, 2017 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of December 31, 2017			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$86	$ 78	$ —	$41
Nuclear Production, net of Accumulated Depreciation	605	661	211	802
Nuclear Fuel In-Service, net of Accumulated Depreciation	104	124	—	153
Construction Work in Progress (including nuclear fuel)	245	90	1	25
Total Assets	$1,040	$ 953	$ 212	$1,021
Liabilities				
Asset Retirement Obligation	$302	$ 249	$ —	$205
Total Liabilities	$302	$ 249	$ —	$205
Net Assets	$738	$ 704	$ 212	$816
NRC License Renewal Term	2046	2036/2040	N/A	2033/2034
% Owned	100 %	57 %	Various	50 %

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.
The precise timing of any potential early retirement and resulting financial statement impact may be affected by a number of factors, including co-owner considerations, the results of any transmission system reliability study assessments and decommissioning trust fund requirements and other commitments, as well as future energy prices.
Power maintains a NDT Fund that funds its decommissioning obligations. See Note 9. Available-for-Sale Securities.
Note 4. Variable Interest Entity (VIE)
VIE for which PSEG LI is the Primary Beneficiary
PSEG LI consolidates Long Island Electric Utility Servco, LLC (Servco), a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.
Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco's operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI's annual contractual management fee, in certain situations, could be

partially offset by Servco’s annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

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 2017, 2016 and 2015, Servco recorded $438 million, $410 million

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and $375 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, 2017 and 2016 is detailed below:

	PSE&G	Power	Other	PSEG Consolidated
	Millions			
2017				
Transmission and Distribution:				
Electric Transmission	$10,425	$—	$—	$ 10,425
Electric Distribution	8,455	—	—	8,455
Gas Distribution and Transmission	7,122	—	—	7,122
Construction Work in Progress	1,735	—	—	1,735
Other	512	—	—	512
Total Transmission and Distribution	28,249	—	—	28,249
Generation:				
Fossil Production	—	4,923	—	4,923
Nuclear Production	—	2,893	—	2,893
Nuclear Fuel in Service	—	745	—	745
Other Production-Solar	593	757	—	1,350
Construction Work in Progress	—	2,339	—	2,339
Total Generation	593	11,657	—	12,250
Other	275	98	359	732
Total	$29,117	$11,755	$359	$ 41,231

	PSE&G	Power	Other	PSEG Consolidated
	Millions			
2016				
Transmission and Distribution:				
Electric Transmission	$9,149	$—	$—	$ 9,149
Electric Distribution	7,976	—	—	7,976
Gas Distribution and Transmission	6,458	—	—	6,458
Construction Work in Progress	1,501	—	—	1,501
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 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,			
		2017		2016	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
PSE&G:					
Transmission Facilities	Various	$162	$ 58	$169	$ 65
Power:					
Coal Generating:					
Conemaugh	23 %	$408	$ 178	$408	$ 166
Keystone	23 %	$409	$ 187	$409	$ 176
Nuclear Generating:					
Peach Bottom	50 %	$1,328	$ 348	$1,272	$ 306
Salem	57 %	$1,147	$ 277	$1,077	$ 304
Nuclear Support Facilities	Various	$239	$ 81	$238	$ 71
Pumped Storage Facilities:					
Yards Creek	50 %	$44	$ 26	$42	$ 25
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, 2017 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

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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, 2017	2016
	Millions	
Regulatory Assets		
Current		
New Jersey Clean Energy Program	$128	$142
Weather Normalization Clause (WNC)	40	49
Electric Energy Costs—Basic Generation Service	23	2
FERC Formula Rate True-up	12	—
Other	8	6
Total Current Regulatory Assets	$211	$199
Noncurrent		
Pension and OPEB Costs	$1,488	$1,403
Manufactured Gas Plant (MGP) Remediation Costs	358	403
Deferred Income Taxes	282	507
Storm Damage Deferrals	241	239
Electric Transmission and Gas Cost of Removal	199	189
Remediation Adjustment Charge (RAC) (Other SBC)	172	180
Conditional Asset Retirement Obligation	162	157
Green Program Recovery Charges (GPRC)	98	91
Unamortized Loss on Reacquired Debt and Debt Expense	55	61
Gas Costs—Basic Gas Supply Service (BGSS)	30	—
FERC Formula Rate True-up	16	—
Other	121	89
Total Noncurrent Regulatory Assets	$3,222	$3,319
Total Regulatory Assets	$3,433	$3,518

	As of December 31, 2017	2016
	Millions	
Regulatory Liabilities		
Current		
Gas Costs —BGSS	$30	$6
Gas Margin Adjustment Clause	12	11
GPRC	3	28
FERC Formula Rate True-up	—	34
Other	2	9
Total Current Regulatory Liabilities	$47	$88
Noncurrent		
Excess Deferred Income Tax Regulatory Liability	$2,868	$—

Electric Distribution Cost of Removal	80	94
Mark-to-Market (MTM) Contracts	—	20
Other	—	4
Total Noncurrent Regulatory Liabilities	$2,948	$118
Total Regulatory Liabilities	$2,995	$206

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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 as assets are retired.
- 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. In December 2017, new tax legislation was enacted (Tax Act) reducing the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018. PSE&G is subject to Financial Accounting Standards Board (FASB) Accounting Standards Codification 740, Income Taxes (ASC 740), which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate was enacted. The impact of reduction in tax rate is the primary reason for the decrease in the Regulatory Asset.
- 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.
- Electric Energy Costs—Basic Generation Service: These costs represent the over or under recovered amounts associated with Basic Generation Services (BGS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for electric 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. Over or under recovered balances with interest are returned or recovered through monthly filings.
- Excess Deferred Income Tax Regulatory Liability: The $2.9 billion Regulatory Liability represents the future revenue reduction of PSE&G's existing $2.1 billion Accumulated Deferred Income Tax liabilities that are in excess of what is needed to offset future tax liabilities as a result of the Tax Act that reduces the federal corporate income tax rate from a maximum of 35% to 21% effective January 1, 2018. The excess deferred income taxes are primarily related to the difference between book and tax plant depreciation and under the new tax legislation cannot be returned to customers any faster than over the remaining regulatory lives of the related property. For the remaining excess deferred taxes, the mechanism and timing of these refunds will be determined by the BPU and FERC.
- FERC Formula Rate True-up: Over or under collection of transmission earnings calculated using a FERC approved formula. Over or under collected balances with interest are returned or recovered through the subsequent annual filing.
- Gas Costs—Basic Gas Supply Service: These costs represent the over or under recovered 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. Over or under collected balances are returned or recovered through an annual filing. Interest is accrued only on over recovered balances.
- 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. Over or under recovered balances with interest are returned or recovered through the subsequent annual filing.
- GPRC: This amount represents costs of the over or under collected balances associated with various renewable energy and energy efficiency programs. The Company files annually with the BPU for recovery of amounts that include a return on and of its investment over the lives of the underlying investments and capital assets which range from 5 to 10 years. Interest is accrued monthly on any over or under recovered balances. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program (EEE), 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, Solar Loan III Program and the Energy Efficiency 2017 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 over a seven year period with interest.

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- 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.
- New Jersey Clean Energy Program: The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2018. The BPU funding requirements are recovered through the SBC.
- 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 with interest through an annual filing.
- 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. Over or under recovered balances with interest are to be returned or recovered through an annual filing.
- Storm Damage Deferrals: Costs incurred in the cleanup of major storms in 2010 through 2017. As of December 31, 2017, 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.
- 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.
- WNC: This represents the over or under recovery of gas margin under the BPU's weather normalization clause which is filed annually. 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 returned to customers in the next winter season while under recoveries (subject to an earnings cap) are recovered from customers in the next winter season.

Significant 2017 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- Electric and Gas Distribution Base Rate Filing—In January 2018, PSE&G filed a distribution base rate case as required as a condition of approval of its Energy Strong Program approved by the BPU in 2014. The filing requests an approximate one percent increase in revenues and seeks to recover investments made to strengthen electric and gas distribution systems. In its filing, PSE&G requested that these rates take into account a reduction in the revenue requirement as a result of the federal corporate income tax rate reduction from 35% to 21% provided in the Tax Act, including a one-time credit for estimated excess income taxes collected between January 1, 2018 and the time new rates go into effect, and the flow back to customers of certain additional tax benefits. PSE&G anticipates the new base rates will go into effect in the fourth quarter of 2018.

Separately, in January 2018, the BPU issued an order commencing a proceeding to ensure that the rate revenue resulting from expenses relating to taxes reflected in rates but no longer owed as the result of the Tax Act shall be passed onto the ratepayers. The BPU directed New Jersey utilities (including PSE&G) to make filings by March 2, 2018 setting forth interim rates to be effective April 1, 2018 reflecting the new federal corporate tax rate, and to subsequently file proposed final rates, effective July 1, 2018, incorporating all other effects of the Tax Act. This proceeding is currently pending.

- Transmission Formula Rate Filings—In June 2017, PSE&G filed its 2016 true-up adjustment pertaining to its transmission formula rates in effect for 2016. This resulted in an adjustment of $12 million more than the 2016 originally filed revenues.

For the year ended December 31, 2017, PSE&G recorded an estimated true-up adjustment of $16 million to its 2017 Annual Formula rate. That true-up will be filed by no later than June 15, 2018.

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In October 2017, the 2018 Annual Formula Rate Update was filed with FERC and requested approximately $212 million in increased annual transmission revenues effective January 1, 2018, subject to true-up. In January 2018, PSE&G filed with FERC a revised 2018 Annual Transmission Formula Rate Update reducing the 2018 transmission annual revenue requirement to reflect the federal corporate income tax rate reduction from 35% to 21%, effective January 1, 2018, provided in the Tax Act. This change in the federal corporate tax rate reduces the annual revenue requirement by $148 million. The revised increase in annual transmission revenues effective January 1, 2018 is $64 million.

- 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 2017, PSE&G submitted the planned update to its March Energy Strong cost recovery petition, originally filed in March 2017, to include Energy Strong investments in service as of May 31, 2017. This filing requested estimated annual increases in electric and gas revenues of $16 million and $2 million, respectively. In August 2017, the BPU approved these rate increases effective September 1, 2017.

In September 2017, 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, 2017 through November 30, 2017. The filing was updated in December 2017 requesting an annual increase in electric revenues of $8 million. This matter is pending.

- Gas System Modernization Program (GSMP)—In July of each year, PSE&G files with the BPU for base rate recovery of GSMP investments which include a return of and on its investment.

In December 2017, the BPU approved PSE&G’s annual GSMP cost recovery petition, originally filed in July 2017, and updated in October 2017, to include GSMP investments in service as of September 30, 2017. The BPU approved an annual increase in gas revenues of $25 million, effective January 1, 2018.

- BGSS—In June 2017, PSE&G made its annual BGSS filing with the BPU requesting an increase in the BGSS rate from approximately 34 cents to 37 cents per therm effective October 1, 2017. In September 2017, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was increased. In December 2017 and February 2018, PSE&G filed with the BPU for self-implementing monthly bill credits of 15 cents per therm for the months of January, February and March 2018. These monthly bill credits are estimated to provide approximately $100 million in customer credits. In November 2017, a filing was made by the Retail Energy Supply Association (RESA) with the BPU requesting that the BPU revisit the BGSS process and establish a gas capacity release program. This filing, which remains pending, is applicable to all New Jersey gas utilities.

- Green Program Recovery Charges (GPRC)—Each year PSE&G files with the BPU for annual recovery for the 11 combined components of its electric and gas Green Program investments which include a return on its investment and recovery of expenses.

In March 2017, the BPU gave final approval to PSE&G’s 2016 GPRC cost recovery petition to recover approximately$37 million and $13 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G’s implementation of these BPU approved GPRC programs for the period October 1, 2016 through September 30, 2017. The rates were effective May 1, 2017. This Order also included the return of approximately $5 million in remaining overcollections from the completed Securitization Transition Charge.

In June 2017, PSE&G filed its 2017 GPRC cost recovery petition requesting recovery of approximately $47 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 for the period October 1, 2017 through September 30, 2018. This proceeding is ongoing.

In August 2017, the BPU approved PSE&G’s petition for an Energy Efficiency 2017 Program (EE 2017) to extend three existing energy efficiency subprograms (multi-family, direct install and hospital efficiency) and establish two new residential energy efficiency offerings. The two new offerings include deployment of smart thermostats and a pilot program to provide residential customers with energy usage information enabling them to reduce consumption. The Order allows PSE&G to extend the subprogram offerings and establish the residential energy efficiency subprograms under its existing energy efficiency clause recovery process. The EE 2017 allows for $69 million of additional investment and $16 million of additional administrative and information technology costs. The EE 2017 was added as the 11th component of the GPRC rate effective September 1, 2017.

- Weather Normalization Clause—In April 2017, the BPU gave final approval to PSE&G petition to collect $54 million in net deficiency gas revenues as a result of the warmer than normal 2015-2016 Winter Period.

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In September 2017, the BPU approved on a provisional basis, PSE&G's petition to collect $31 million in net deficiency gas revenues as a result of the warmer than normal 2016-2017 Winter Period and a remaining carryover balance of $24 million in net deficiency gas revenues from the 2015-2016 Winter Period for a total recovery of $55 million in net deficiency revenues. The deficiency will be collected from customers over the 2017-2018 and 2018-2019 Winter Periods (October 1 through May 31). Final approval in this matter is pending.

- Remediation Adjustment Charge (RAC)—In June 2017, the BPU approved PSE&G's filing with respect to its RAC 24 petition allowing recovery of $41 million effective July 10, 2017 related to net Manufactured Gas Plant expenditures from August 1, 2015 through July 31, 2016. In February 2018, PSE&G filed a RAC 25 Petition with the BPU requesting recovery of $63 million of net Manufactured Gas Plant expenditures from August 1, 2016 through July 31, 2017. This matter is pending.
- Universal Service Fund (USF)/Lifeline—In September 2017, 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, 2017. PSE&G earns no margin on the collection of the USF and Lifeline programs resulting in no impact on its Consolidated Statement of Operations.

Note 7. Long-Term Investments

Long-Term Investments as of December 31, 2017 and 2016 included the following:

	As of December 31,	
	2017	2016
	Millions	
PSE&G		
Life Insurance and Supplemental Benefits	$130	$140
Solar Loans	150	159
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	87	102
Energy Holdings		
Lease Investments	565	649
Total Long-Term Investments	$932	$1,050

(A) During the three years ended December 31, 2017, 2016 and 2015, dividends from these investments were $18 million, $18 million and $16 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.

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During the first quarter of 2017, due to continuing liquidity issues facing REMA, economic challenges facing coal generation in PJM, and based upon an ongoing review of available alternatives as well as certain recent discussions with REMA management, Energy Holdings recorded an additional $55 million pre-tax charge for its current best estimate of loss related to the lease receivables.
In June 2017, GenOn Energy, Inc. (GenOn) and certain of its subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code. REMA was not included in the GenOn filing. Energy Holdings continues to monitor the restructuring of GenOn and its possible impacts on REMA and continues to discuss the situation with various parties relevant to this matter. During the second quarter of 2017, Energy Holdings completed its review of estimated residual values embedded in its leveraged lease portfolio of generating assets and the outcome indicated that one of the residual value estimates was lower than the recorded residual value due to a further deterioration of market conditions and changes to operating cost estimates. This decline was determined to be other than temporary. As a result, a pre-tax write-down of $7 million was recorded in the quarter ended June 30, 2017. In addition, based on an ongoing review of (i) the liquidity challenges facing REMA and (ii) available alternatives, Energy Holdings recorded an additional $15 million pre-tax charge in the quarter ended June 30, 2017 for its current best estimate of loss related to lease receivables. Pre-tax write-downs and additional charges are reflected in Operating Revenues and are included in Gross Investment in Leases as of December 31, 2017.
In January 2018, certain subsidiaries of Energy Holdings, REMA, certain holders of the pass-through certificates and other parties entered into a Forbearance Agreement (Forbearance) relating to the Conemaugh facility. Pursuant to the Forbearance, the parties thereto agreed to temporarily forbear from exercising rights and remedies related to certain events of default related to REMA’s obligation to procure additional qualifying credit support. The Forbearance will remain effective until the earlier of (i) the later of (a) April 15, 2018 and (b) two weeks following the date on which Energy Holdings subsidiaries, REMA and/or the consenting certificate holders provide written notice to REMA of its intention to terminate the Forbearance, and (ii) the date on which any event of termination as specified in the Forbearance occurs.
PSEG cannot predict the outcome of GenOn’s restructuring process or 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 additional pre-tax write-offs up to its gross investment in these facilities and may also be required to accelerate and pay material deferred tax liabilities to the Internal Revenue Service (IRS).
The following table shows Energy Holdings’ gross and net lease investment as of December 31, 2017 and 2016.

	As of December 31,	
	2017	2016
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$546	$629
Estimated Residual Value of Leased Assets	326	346
Total Investment in Rental Receivables	872	975
Unearned and Deferred Income	(307)	(326)
Gross Investments in Leases	565	649
Deferred Tax Liabilities	(480)	(674)
Net Investments in Leases	$85	$(25)

In December 2017, new tax legislation was enacted, reducing the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018. PSEG is subject to ASC 740, which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate was enacted. The impact of the reduced tax rate is the primary reason for the decrease in Deferred Tax Liabilities. For additional information, see Note 20. Income Taxes.

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

	Years Ended December 31,		
	2017	2016	2015
	Millions		
Pre-Tax Income (Loss) from Leases	$(69)	$(135)	$ 12
Income Tax Expense (Benefit) on Income from Leases	$(26)	$(51)	$ 5

Equity Method Investments
Power had the following equity method investments as of December 31, 2017 and 2016:

Name	As of December 31, 2017	2016	Location	% Owned
	Millions			
Power				
Keystone Fuels, LLC	$ 8	$ 7	PA	23%
Conemaugh Fuels, LLC	8	8	PA	23%
PennEast Pipeline	—	11	PA	10%
Kalaeloa	71	76	HI	50%
Total	$ 87	$ 102		

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. Interest income on the loans is recorded on an accrual basis. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. In the event of a loan default, the basis of the solar loan would be recovered through a regulatory recovery mechanism. None of the solar loans are impaired; however, in the event a loan becomes impaired, the basis of the loan would be recovered through a regulatory recovery mechanism.
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, 2017	2016
	Millions	
Commercial/Industrial	$ 158	$ 164
Residential	10	11
Total	$ 168	$ 175

Energy Holdings

Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $85 million as of December 31, 2017 and $(25) million as of December 31, 2016 (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, 2017	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2017	
	Millions	
AA	$	15
BBB+, BBB, BBB-	316	
BB-	133	
CCC-	82	
Total	$	546

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, 2017, the gross investment in the leases of such assets, net of non-recourse debt, was $335 million, ($(67) 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	$	132	64	%	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$	85	64	%	1,036	Gas	BB-	NRG Energy, Inc.
Keystone Station Units 1 and 2	PA	$	20	17	%	1,711	Coal	CCC-	REMA (A)
Conemaugh Station Units 1 and 2	PA	$	20	17	%	1,711	Coal	CCC-	REMA (A)
Shawville Station Units 1, 2, 3 and 4	PA	$	78	100	%	596	Gas	CCC-	REMA (A)

(A) GenOn Energy Inc. (GenOn), and certain of its subsidiaries (which did not include REMA) filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. GenOn is currently engaged in a balance sheet restructuring, which will take an undetermined time to complete. Certain subsidiaries of Energy Holdings, REMA, consenting holders of the pass-through certificates and other parties entered into a Forbearance relating to the Conemaugh facility. For additional information, see Note 7. Long-Term Investments.

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. 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.

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.

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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, 2017 was approximately $756 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, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$405	$ 245	$ (2)	$648
International	311	99	(3)	407
Total Equity Securities	716	344	(5)	1,055
Debt Securities				
Government	586	2	(4)	584
Corporate	400	4	(2)	402
Total Debt Securities	986	6	(6)	986
Other Securities	92	—	—	92
Total NDT Available-for-Sale Securities	$1,794	$ 350	$ (11)	$2,133

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$439	$ 214	$ (3)	$650
International	266	49	(8)	307
Total 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 as of December 31, 2016, which is part of the NDT Fund.

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The cost of these securities was determined on the basis of specific identification.
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, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 24	$ 8
Accounts Payable	$ 74	$ 5

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

	As of December 31, 2017				As of December 31, 2016			
	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)								
Domestic	$40	$ (2)	$—	$ —	$51	$ (3)	$2	$ —
International	29	(3)	2	—	69	(7)	6	(1)
Total Equity Securities	69	(5)	2	—	120	(10)	8	(1)
Debt Securities								
Government (B)	343	(2)	91	(2)	276	(6)	4	—
Corporate (C)	191	(1)	27	(1)	139	(3)	15	(1)
Total Debt Securities	534	(3)	118	(3)	415	(9)	19	(1)
NDT Available-for-Sale Securities	$603	$ (8)	$120	$ (3)	$535	$ (19)	$27	$ (2)

(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, 2017.

(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 before recovery 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, 2017.

(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 before recovery 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, 2017.

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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,		
	2017	2016	2015
	Millions		
Proceeds from Sales (A)	$2,137	$711	$1,397
Net Realized Gains (Losses):			
Gross Realized Gains	$157	$53	$97
Gross Realized Losses	(23)	(32)	(37)
Net Realized Gains (Losses) on NDT Fund (B)	$134	$21	$60

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.
(B) The cost of these securities was determined on the basis of specific identification.

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 $175 million (after-tax) are included in Accumulated Other Comprehensive Loss on PSEG's and Power's Consolidated Balance Sheets as of December 31, 2017. Under 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), effective January 1, 2018. For additional information, see Note 2. Recent Accounting Standards.

The available-for-sale debt securities held as of December 31, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 42
1 - 5 years	320
6 - 10 years	207
11 - 15 years	40
16 - 20 years	65
Over 20 years	312
Total NDT Available-for-Sale Debt Securities	$ 986

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 2017, other-than-temporary impairments of $12 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

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

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

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	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$22	$ 3	$ —	$25
International	—	—	—	—
Total Equity Securities	$22	$ 3	$ —	$25
Debt Securities				
Government	85	1	(1)	85
Corporate	118	2	(1)	119
Total Debt Securities	203	3	(2)	204
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	$227	$ 6	$ (2)	$231

	As of December 31, 2016			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$11	$ 11	$ —	$22
International	—	—	—	—
Total 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

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, 2017	As of December 31, 2016
	Millions	
Accounts Receivable	$ 2	$ 5
Accounts Payable	$ 1	$ 3

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

	As of December 31, 2017				As of December 31, 2016			
	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)								
Domestic	$—	$ —	$—	$ —	$—	$ —	$ —	$ —
International	—	—	—	—	—	—	—	—
Total Equity Securities	—	—	—	—	—	—	—	—
Debt Securities								
Government (B)	28	—	25	(1)	60	(2)	1	—
Corporate (C)	39	(1)	9	—	46	(2)	3	—
Total Debt Securities	67	(1)	34	(1)	106	(4)	4	—
Rabbi Trust Available-for-Sale Securities	$67	$ (1)	$34	$ (1)	$106	$ (4)	$ 4	$ —

(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 before recovery 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, 2017.

(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 before recovery 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, 2017.

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

	Years Ended December 31,		
	2017	2016	2015
	Millions		
Proceeds from Rabbi Trust Sales (A)	$182	$113	$104
Net Realized Gains (Losses):			
Gross Realized Gains	$17	$6	$3
Gross Realized Losses	(5)	(5)	(2)
Net Realized Gains (Losses) on Rabbi Trust (B)	$12	$1	$1

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.
(B) The cost of these securities was determined on the basis of specific identification.

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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 $2 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2017. The Rabbi Trust available-for-sale debt securities held as of December 31, 2017 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 1
1 - 5 years	37
6 - 10 years	30
11 - 15 years	5
16 - 20 years	18
Over 20 years	113
Total Rabbi Trust Available-for-Sale Debt Securities	$ 204

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 2017, 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, 2017	As of December 31, 2016
	Millions	
PSE&G	$46	$ 43
Power	57	53
Other	128	121
Total Rabbi Trust Available-for-Sale Securities	$231	$ 217

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 10. Goodwill and Other Intangibles

As of December 31, 2017 and 2016, 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 2017 and concluded that goodwill continues to remain unimpaired. In addition to goodwill, as of December 31, 2017 and 2016, Power had intangible assets of $114 million and $98 million, respectively, related to emissions allowances and renewable energy credits. Emissions allowances and renewable energy credits are recorded at cost and evaluated for impairment at least annually. 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. The changes to Power's intangible assets during 2016 and 2017 are presented in the following table:

	Emissions Allowances	Renewable Energy Credits	Total Other Intangibles
	Millions		
Balance as of January 1, 2016	$62	$ 40	$ 102
Retirements	(6)	(94)	(100)
Purchases	—	99	99
Sales and Transfers, net	(1)	(1)	(2)
Impairments	(1)	—	(1)
Balance as of December 31, 2016	$54	$ 44	$ 98
Retirements	(7)	(93)	(100)
Purchases	27	90	117
Sales and Transfers, net	—	(1)	(1)
Balance as of December 31, 2017	$74	$ 40	$ 114

Note 11. Asset Retirement Obligations (AROs)

PSEG, PSE&G and Power recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists to remove or dispose of an asset or some component of an asset at retirement. 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 with the corresponding expense recorded in Operation and Maintenance.
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, ash ponds, 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 2016 and 2017 are presented in the following table:

	PSEG	PSE&G	Power	Other
	Millions			
ARO Liability as of January 1, 2016	$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
Liabilities Settled	(29)	(8)	(21)	—
Liabilities Incurred	1	—	1	—
Accretion Expense	30	—	30	—
Accretion Expense Deferred and Recovered in Rate Base (A)	12	12	—	—
Revision to Present Values of Estimated Cash Flows	284	(5)	289	—
ARO Liability as of December 31, 2017	$1,024	$ 212	$810	$ 2

(A) Not reflected as expense in Consolidated Statements of Operations

During 2017, PSE&G recorded a reduction to 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 2017, Power recorded an increase to its ARO liabilities primarily due to a higher assumed probability of early retirement of its nuclear units of $276 million (See Note 3. Early Plant Retirements for additional information).

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.

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, the total net periodic benefit costs, net of amounts capitalized, decreased by approximately $48 million for the year ended December 31, 2017, 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.
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.

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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, 2017 and 2016. 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	
	2017	2016	2017	2016
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$5,772	$5,522	$1,754	$1,612
Service Cost	114	109	17	17
Interest Cost	204	202	63	59
Actuarial (Gain) Loss	564	219	199	127
Gross Benefits Paid	(295)	(282)	(57)	(57)
Plan Amendments	—	2	—	(4)
Benefit Obligation at End of Year (A)	$6,359	$5,772	$1,976	$1,754
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$5,193	$5,039	$420	$374
Actual Return on Plan Assets	903	403	77	32
Employer Contributions	11	33	71	71
Gross Benefits Paid	(295)	(282)	(57)	(57)
Fair Value of Assets at End of Year	$5,812	$5,193	$511	$420
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	$(547)	$(579)	$(1,465)	$(1,334)
Additional Amounts Recognized in the Consolidated Balance Sheets				
Current Accrued Benefit Cost	(10)	(11)	(10)	(10)
Noncurrent Accrued Benefit Cost	(537)	(568)	(1,455)	(1,324)
Amounts Recognized	$(547)	$(579)	$(1,465)	$(1,334)
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (B)				
Prior Service Cost	$(46)	$(63)	$(3)	$(14)
Net Actuarial Loss	1,721	1,763	629	523
Total	$1,675	$1,700	$626	$509

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits. The vested benefit obligation is the actuarial present value of the vested benefits to which the employee is currently entitled but based on the employee’s expected date of separation of retirement.

(B) Includes $683 million ($406 million, after-tax) and $679 million ($398 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2017 and 2016, respectively. Also includes Regulatory Assets of $1,485 million and Deferred Assets of $133 million as of December 31, 2017 and Regulatory Assets of $1,396 million and Deferred Assets of $134 million as of December 31, 2016.

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, 2017, PSEG had funded approximately 91% of its projected benefit obligation. This percentage does not include $231 million of assets in the Rabbi Trust as of December 31, 2017 which were used partially to fund the nonqualified pension plans. As of December 31, 2017, the nonqualified pension plans included in the projected benefit obligation in the above table were $167 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 $6.1 billion as of December 31, 2017 and $5.6 billion as of December 31, 2016.
The following table provides the components of net periodic benefit cost for the years ended December 31, 2017, 2016 and 2015.

	Pension Benefits			Other Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2017	2016	2015	2017	2016	2015
	Millions					
Components of Net Periodic Benefit Cost						
Service Cost	$114	$109	$123	$ 17	$ 17	22
Interest Cost	204	202	234	63	59	67
Expected Return on Plan Assets	(394)	(394)	(414)	(34)	(31)	(31)
Amortization of Net						
Prior Service Credit	(18)	(19)	(19)	(11)	(14)	(14)
Actuarial Loss	97	158	150	51	40	43
Net Periodic Benefit Cost	$3	$56	$74	$ 86	$ 71	$ 87

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,		
	2017	2016	2015	2017	2016	2015
	Millions					
PSE&G	$(4)	$ 29	$ 40	$ 54	$ 43	$ 55
Power	1	16	21	27	23	27
Other	6	11	13	5	5	5
Total Benefit Cost	$3	$ 56	$ 74	$ 86	$ 71	$ 87

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2017	2016	2017	2016
	Millions			
Net Actuarial (Gain) Loss in Current Period	$55	$211	$156	$125
Amortization of Net Actuarial Gain (Loss)	(97)	(158)	(50)	(40)
Prior Service Cost (Credit) in current period	—	1	—	(3)
Amortization of Prior Service Credit	18	19	11	14
Total	$(24)	$73	$117	$96

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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 2018 are as follows:

	Pension Benefits 2018	Other Benefits 2018
	Millions	
Actuarial Loss	$85	$ 64
Prior Service Credit	$(18)	$ (1)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2017	2016	2015	2017	2016	2015
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	3.73%	4.29%	4.54%	3.76 %	4.37 %	4.58 %
Rate of Compensation Increase	3.90%	3.61%	3.61%	3.90 %	3.61 %	3.61 %
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	4.29%	4.54%	4.20%	4.37 %	4.58 %	4.21 %
Service Cost Interest Rate	4.53%	4.81%	4.20%	4.64 %	4.87 %	4.21 %
Interest Cost Interest Rate	3.63%	3.75%	4.20%	3.69 %	3.76 %	4.21 %
Expected Return on Plan Assets	7.80%	8.00%	8.00%	7.80 %	8.00 %	8.00 %
Rate of Compensation Increase	3.61%	3.61%	3.61%	3.61 %	3.61 %	3.61 %
Assumed Health Care Cost Trend Rates as of December 31						
Health Care Costs						
Immediate Rate				7.93 %	7.55 %	7.75 %
Ultimate Rate				4.75 %	4.75 %	4.75 %
Year Ultimate Rate Reached				2026	2025	2025
				Millions		
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$13	$11	$12
Postretirement Benefit Obligation				$240	$191	$194
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$(10)	$(9)	$(10)
Postretirement Benefit Obligation				$(198)	$(160)	$(160)

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, 2017, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 92% and 8%, 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, 2017 and 2016, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2017			
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)	$133	$ 117	$ 16	$ —
Equity Securities				
Common Stock (B)	1,275	1,275	—	—
Commingled (C)	1,401	1,218	183	—
Preferred Stock (B)	6	6	—	—
Debt Securities (D)				
U.S. Treasury	571	—	571	—
Government—Other	272	—	272	—
Corporate	963	—	963	—
Subtotal Fair Value	$4,621	$ 2,616	$ 2,005	$ —
Measured at net asset value practical expedient				
Commingled—Equities (E)	1,675			
Private Equity (F)	14			
Total Fair Value (G)	$6,310			

	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	$ —
Equity Securities				
Common Stock (B)	944	944	—	—
Commingled (C)	1,387	1,247	140	—
Preferred Stock (B)	1	1	—	—
Debt Securities (D)				
U.S. 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				
Commingled—Equities (E)	1,604			
Private Equity (F)	16			
Total Fair Value (G)	$5,599			

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(A) The Collective Investment Fund publishes a daily net asset value (NAV) which participants may use for daily redemptions without restrictions (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Common stocks and preferred stocks are measured using observable data in active markets and considered Level 1.

(C) Commingled Funds that allow daily redemption at their daily published NAV without restrictions are classified as Level 1. Commingled Funds that publish daily NAV but with certain near term redemption restrictions which prevent redemption at the published daily NAV are classified as Level 2.

(D) Debt 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) In 2016, as part of the implementation of the accounting guidance on investments measured at fair value using NAV as a practical expedient, certain 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. 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 five 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.

(F) Private equity investments primarily include various limited partnerships that invest in either operating companies through acquisitions or developing a portfolio of non-US distressed investments to maximize total return on capital. These investments are valued at NAV (or its equivalent) on an annual basis and have significant redemption restrictions preventing redemption until fund liquidation and limited ability to sell these investments. Fund liquidation is not expected to occur for several more years. These investments have been removed from the fair value hierarchy in accordance with the guidance on NAV practical expedient.

(G) Excludes net receivable of $13 million and $14 million at December 31, 2017 and 2016, respectively, which consists of interest, dividends and 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	2017	2016
Equity Securities	69 %	70 %
Debt Securities	29	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 7.8% for 2017 and will be 7.8% for 2018. 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.

Plan Contributions

PSEG has no planned contributions to its pension plans in 2018. PSEG plans to make discretionary contributions of $14 million into its OPEB plan during 2018.

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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	
2018	$337	$ 88
2019	331	92
2020	341	96
2021	352	101
2022	364	105
2023-2027	1,954	560
Total	$3,679	$ 1,042

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,		
	2017	2016	2015
	Millions		
PSE&G	$ 25	$ 24	$ 22
Power	11	12	12
Other	5	5	5
Total Employer Matching Contributions	$ 41	$ 41	$ 39

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 Entity. 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, 2017 and 2016. 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 2017	Pension Benefits 2016	Other Benefits 2017	Other Benefits 2016
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year	$ 262	$ 211	$ 452	$ 375
Service Cost	27	24	15	12
Interest Cost	11	9	19	17
Actuarial (Gain) Loss	22	14	60	50
Gross Benefits Paid	(2)	(1)	(4)	(2)
Plan Amendments	—	5	—	—
Benefit Obligation at End of Year (A)	$ 320	$ 262	$ 542	$ 452
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$ 134	$ 97	$—	$—
Actual Return on Plan Assets	24	10	—	—
Employer Contributions	35	28	4	2
Gross Benefits Paid	(2)	(1)	(4)	(2)
Fair Value of Assets at End of Year	$ 191	$ 134	$—	$—
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	$ (129)	$ (128)	$ (542)	$ (452)
Additional Amounts Recognized in the Consolidated Balance Sheets				
Accrued Pension Costs of Servco	$ (129)	$ (128)	N/A	N/A
OPEB Costs of Servco	N/A	N/A	(542)	(452)
Amounts Recognized (B)	$ (129)	$ (128)	$ (542)	$ (452)

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits. The vested benefit obligation is the actuarial present value of the vested benefits to which the employee is currently entitled but based on the employee's expected date of separation of retirement.

(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 2017, 2016 and 2015 were $35 million, $28 million and $30 million, respectively. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2017. The OPEB-related revenues earned and costs incurred were $4 million and $2 million in 2017 and 2016, respectively, and immaterial for 2015.

The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits 2017	Pension Benefits 2016	Pension Benefits 2015	Other Benefits 2017	Other Benefits 2016	Other Benefits 2015
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	3.90%	4.61%	4.92%	3.96 %	4.71 %	4.97 %
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						
Health Care Costs						
Immediate Rate				7.69 %	7.55 %	7.55 %

Ultimate Rate	4.75 %	4.75 %	4.75 %
Year Ultimate Rate Reached	2026	2025	2025
	Millions		
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs			
Postretirement Benefit Obligation	$131	$97	$75
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs			
Postretirement Benefit Obligation	$(99)	$(75)	$(60)

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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, 2017 and 2016, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2017			
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)	$137	$ —	$ 137	$ —
Commingled Bonds (A)	54	—	54	—
Total	$191	$ —	$ 191	$ —

	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	$ —

(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).

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 31,	
Investments	2017	2016
Equity Securities	72 %	71 %
Debt Securities	28	29
Total Percentage	100%	100%

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 7.6% for 2017 and will be 7.6% for 2018. This expected return was determined based on the study discussed above, including a premium for active management.

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Plan Contributions
Servco plans to contribute $40 million into its pension plan during 2018.
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	
2018	$3	$ 4
2019	4	6
2020	5	8
2021	7	9
2022	9	12
2023-2027	78	87
Total	$106	$ 126

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, 2017, 2016 and 2015 were $6 million, $5 million and $4 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

- 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).

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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, 2017 and 2016.

	As of December 31, 2017	As of December 31, 2016
	Millions	
Face Value of Outstanding Guarantees	$1,701	$ 1,806
Exposure under Current Guarantees	$153	$ 139
Letters of Credit Margin Posted	$103	$ 157
Letters of Credit Margin Received	$32	$ 99
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$—	$ —
Counterparty Cash Margin Received	$(1)	$ (1)
Net Broker Balance Deposited (Received)	$147	$ 57
Additional Amounts Posted		
Other Letters of Credit	$61	$ 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. In June 2017, Power sold its minority interest in PennEast and upon disposition, PSEG's $106 million guarantee that had supported Power's payment obligations related to PennEast was terminated.

Environmental Matters
Passaic River
Historic operations of PSEG companies and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by Federal and State agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex in violation of various statutes as discussed as follows.

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

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA and a comprehensive study of the entire 17 miles of the lower Passaic River needed to be performed. 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.

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In early 2007, certain 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. The CPG has 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 7.6 percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately 1.9 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. Certain PRPs are currently involved in discussions with the EPA regarding cost allocations and related indemnification matters. We cannot predict the outcome of these discussions, or whether individual PRPs will be able to meet their obligations, either of which could have a material impact on PSE&G's and Power's allocation of costs.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River with an estimated cost to remediate the lower 17 miles of the Passaic River ranging from approximately $518 million to $3.2 billion on an undiscounted basis.

In March 2016, the EPA released its Record of Decision (ROD) for the EPA's own Focused Feasibility Study (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 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. Occidental Chemical Corporation, one of the PRPs, has committed to perform the remedial design required by the ROD Remedy, reserving its right of cost contribution from all other PRPs.

In September 2017, the EPA concluded that an Agency-commenced allocation process for the Passaic River's lower 8.3 miles should include only certain PRPs. The allocation is intended to lead to a consent decree in which certain of the PRPs agree to perform the remedial action under EPA oversight. Discussions on the matter are ongoing.

Conversations between the EPA and the PRPs regarding remediation of the Passaic River's upper 9 miles are ongoing.

Based upon (i) the estimated cost of the ROD Remedy, (ii) PSEG's estimate of PSE&G's and Power's shares of that cost, and (iii) the continued ability of PSE&G to recover such costs in its rates, as of December 31, 2017, PSEG has accrued approximately $57 million. Of this amount $46 million has been accrued by PSE&G as an Environmental Costs Liability and a corresponding Regulatory Asset and $11 million has been accrued by Power as an Other Noncurrent Liability with the corresponding O&M Expense recorded in the periods when the liability was accrued.

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

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stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $358 million and $403 million on an undiscounted basis 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 $358 million as of December 31, 2017. Of this amount, $79 million was recorded in Other Current Liabilities and $279 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $358 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 to what extent 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.

Clean Water Act (CWA) 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 cooling water intake rule that establishes 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, based on studies related to impingement mortality and entrainment and submit the results with their permit applications to be conducted by the facilities seeking renewal permits.

Several environmental organizations and certain energy industry groups have filed suit under the Clean Water Act and the Endangered Species Act. The cases have been consolidated at the Second Circuit and a decision remains pending.

In June 2016, the NJDEP issued a final NJPDES permit for Salem. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the CWA, it requires additional studies and the selection of technology to address impingement for the service water system. The final permit does not mandate specific service water system modifications but, 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 NJPDES renewal permit for Salem. NJDEP has granted the hearing request, but it has not yet been scheduled. 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 CWA. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

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 intakes 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 CWA Section 316(b) final rule, Power has proposed to 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. Power is currently awaiting action by the CTDEEP to issue a draft and then a final permit.

Power has negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all of its conditions precedent 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. 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 (CSC) issued an order to approve siting Bridgeport Harbor Station unit 5 (BH5). All major environmental permits have been received; however, secondary approvals are still being obtained to allow operations to begin in mid-2019. Power's obligations under the CEBA are being monitored regularly and carried out as needed.

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 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, if feasible; 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 impacted cable was repaired in late-September 2017; however, dielectric fluid continues to appear on the surface and so the investigation and response actions related to the fluid discharge are ongoing. PSE&G may determine that retirement of the affected facilities would be appropriate. Also ongoing is the process to determine ultimate responsibility for the costs to address the leak among PSE&G, Con Edison and NADC, including an action filed by PSE&G in New Jersey federal court seeking damages from NADC. In that action, NADC has also pursued counterclaims against PSE&G and Con Edison seeking damages for its costs to address the leak. In addition, NADC provided notice to the New Jersey Secretary of Transportation of several alleged violations by Con Edison and PSE&G of regulations prescribed under the Hazardous Liquids Pipeline Safety Act (HLPSA), a requirement to preserve NADC's right to pursue injunctive relief under the HLPSA. Based on the information currently available and depending on the outcome of the New Jersey federal action, PSE&G's portion of the costs to address the leak may be material; however, PSE&G anticipates that it will recover these costs through regulatory proceedings.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG 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. Power's Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

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, 2018 is $287.76 per MW-

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day, replacing the BGS-CIEP auction year price ending May 31, 2018 of $276.83 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			
	2015	2016	2017	2018
36-Month Terms Ending	May 2018	May 2019	May 2020	May 2021 (A)
Load (MW)	2,900	2,800	2,800	2,900
$ per MWh	$99.54	$96.38	$90.78	$91.77

(A) Prices set in the 2018 BGS auction will become effective on June 1, 2018 when the 2015 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 2020 and a significant portion through 2022 at Salem, Hope Creek and Peach Bottom.
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 2021 to support its fossil generation stations.
As of December 31, 2017, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2022
	Millions
Nuclear Fuel	
Uranium	$ 240
Enrichment	$ 391
Fabrication	$ 170
Natural Gas	$ 1,042
Coal	$ 293

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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 has implemented procedures and continues to review its policies and practices to 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 pre-tax charge to income in the amount of $25 million related to this matter.
Since September 2014, FERC Staff has been conducting a preliminary, non-public staff investigation into these matters. While considerable uncertainty remains as to the final resolution of these matters, based upon developments in the investigation in the first quarter of 2017, Power believes the disgorgement and interest costs related to the cost-based bidding matter may range between approximately $35 million and $135 million, depending on the legal interpretation of the principles under the PJM Tariff, plus penalties. Since no point within this range is more likely than any other, Power has accrued the low end of this range of $35 million by recording an additional pre-tax charge to income of $10 million during the three months ended March 31, 2017. Power is unable to reasonably estimate the range of possible loss, if any, for the quantity of energy offered matter or the penalties that FERC would impose relating to either the cost-based bidding or quantity of energy matter. However, any of these amounts could be individually material to PSEG and Power.
Power continues to believe that it has legal defenses that it may assert in a judicial challenge, including the legal defense that its cost-based bidding in a substantial majority of the hours was below the allowed rate under the Tariff and therefore any errors in those hours did not violate the Tariff or were immaterial. Furthermore, it is unclear whether the quantity of energy offered violated any legal requirement. As a result, PSEG and Power cannot predict the final outcome of these matters.
Other Litigation and Legal Proceedings
PSEG and its subsidiaries are party to various lawsuits in the ordinary course of business. In view of the inherent difficulty in predicting the outcome of such matters, PSEG, PSE&G and Power generally cannot predict the eventual outcome of the pending matters, the timing of the ultimate resolution of these matters, or the eventual loss, fines or penalties related to each pending matter.
In accordance with applicable accounting guidance, a liability is accrued when those matters present loss contingencies that are both probable and reasonably estimable. In such cases, there may be an exposure to loss in excess of any amounts accrued. PSEG will continue to monitor the matter for further developments that could affect the amount of the accrued liability that has been previously established.
Based on current knowledge, management does not believe that loss contingencies arising from pending matters, other than the matters described herein, could have a material adverse effect on PSEG's, PSE&G's or Power's consolidated financial position or liquidity. However, in light of the inherent uncertainties involved in these matters, some of which are beyond PSEG's control, and the large or indeterminate damages sought in some of these matters, an adverse outcome in one or more of these matters could be material to PSEG's, PSE&G's or Power's results of operations or liquidity for any particular reporting period.
Nuclear Insurance Coverages and Assessments
Power is a member of the joint underwriting association, American Nuclear Insurers (ANI), which provides nuclear liability insurance coverage at the Salem and Hope Creek site and the Peach Bottom site. The ANI policies are designed to satisfy the financial protection requirements outlined in the Price-Anderson Act, which 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 per incident per site is composed of primary and excess layers. As of December 31, 2017, nuclear sites were required to purchase $450 million of primary liability coverage for each site (through ANI). The primary layer is supplemented by an excess layer, which is an industry self-insurance pool. In the event a nuclear site, which is part of the industry self-insurance pool, has a claim that exceeds the primary layer, each licensee would be assessed a prorated share of the excess layer. The excess layer limit is $13.4 billion. Power's maximum aggregate assessment per incident is $401 million (based on Power's ownership interests in Salem, Hope Creek and Peach Bottom) and its maximum aggregate annual assessment per incident is $60 million. If the damages exceed the limit of liability, Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Further, a decision by the U.S. Supreme Court, not involving Power, held that the Price-Anderson Act did not preclude punitive damage awards based on state law claims.

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Power is also 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 and Hope Creek site and the Peach Bottom site. NEIL also provides replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in the case of adverse loss experience. The current maximum aggregate annual retrospective premium obligation for Power is approximately $76 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance. 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.

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.

Minimum Lease Payments

The total future minimum payments under various operating leases as of December 31, 2017 are:

	PSE&G	Power	Services	Other	Total
	Millions				
2018	$16	$ 5	$ 14	$ 1	$36
2019	9	6	15	1	31
2020	8	3	15	1	27
2021	8	3	15	1	27
2022	7	3	15	1	26
Thereafter	65	38	120	1	224
Total Minimum Lease Payments	$113	$ 58	$ 194	$ 6	$371

Note 14. Debt and Credit Facilities

Long-Term Debt

	Maturity	As of December 31, 2017	2016
		Millions	
PSEG			
Term Loan:			
Variable	2017	$—	$500
Variable	2019	700	—
Total Term Loan		700	500
Senior Notes:			
1.60%	2019	400	400
2.00%	2021	300	300
2.65%	2022	700	—
Total Senior Notes		1,400	700
Principal Amount Outstanding		2,100	1,200
Amounts Due Within One Year		—	(500)
Net Unamortized Discount and Debt Issuance Costs		(9)	(5)
Total Long-Term Debt of PSEG		$2,091	$695

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	Maturity	As of December 31, 2017	2016
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (A):			
9.25%	2021	$134	$134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		149	149
Medium-Term Notes (MTNs) (A):			
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	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	425
3.00%	2027	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	550
3.60%	2047	350	—
Total MTNs		8,509	7,734
Principal Amount Outstanding		8,658	7,883
Amounts Due Within One Year		(750)	—
Net Unamortized Discount and Debt Issuance Costs		(67)	(65)
Total Long-Term Debt of PSE&G		$7,841	$7,818

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	Maturity	As of December 31, 2017	2016
		Millions	
Power			
Senior Notes:			
2.45%	2018	$250	$250
5.13%	2020	406	406
4.15%	2021	250	250
3.00%	2021	700	700
4.30%	2023	250	250
8.63%	2031	500	500
Total Senior Notes		2,356	2,356
Pollution Control Notes:			
Floating Rate (B)	2019	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,400	2,400
Amounts Due Within One Year		(250)	—
Net Unamortized Discount and Debt Issuance Costs		(14)	(18)
Total Long-Term Debt of Power		$2,136	$2,382

(A) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.
(B) The Pennsylvania Economic Development Authority (PEDFA) bond that is serviced and secured by Power Pollution Control Notes, is a variable rate bond that is in weekly reset mode.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2017 are as follows:

Year	PSEG	PSE&G	Power	Total
2018	$—	$ 750	$250	$1,000
2019	1,100	500	44	1,644
2020	—	259	406	665
2021	300	434	950	1,684
2022	700	—	—	700
Thereafter	—	6,715	750	7,465
Total	$2,100	$ 8,658	$2,400	$13,158

Long-Term Debt Financing Transactions

During 2017, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

PSEG

- entered into an agreement for a new term loan maturing June 2019. The term loan has a balance of $700 million at an interest rate of 1 month LIBOR + 0.80% and can be terminated at any time without penalty,
- issued $700 million of 2.65% Senior Notes due November 2022, and
- redeemed at maturity a $500 million term loan at an interest rate of 1 month LIBOR + 0.875% due November 2017.

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PSE&G
- issued $425 million of 3.00% Secured Medium-Term Notes, Series L due May 2027, and
- issued $350 million of 3.60% Secured Medium-Term Notes, Series L due December 2047.

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, 2017, the total available credit capacity was $3.5 billion.

As of December 31, 2017, no single institution represented more than 8% of the total commitments in the credit facilities.

As of December 31, 2017, the total credit capacity was in excess of the anticipated maximum liquidity requirements over PSEG’s 12-month planning horizon.

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, 2017 were as follows:

Company/Facility	As of December 31, 2017 Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facilities (A)	$1,500	$556	$944	Mar 2022	Commercial Paper Support/Funding/Letters of Credit (LC)
Total PSEG	$1,500	$556	$944		
PSE&G					
5-year Credit Facility (A)	$600	$15	$585	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	$600	$15	$585		
Power					
3-year LC Facilities	$200	$112	$88	Mar 2020	Letters of Credit
5-year Credit Facilities	1,900	39	1,861	Mar 2022	Funding/Letters of Credit
Total Power	$2,100	$151	$1,949		
Total	$4,200	$722	$3,478		

(A) 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, 2017, PSEG had $542 million outstanding at a weighted average interest rate of 1.89%. PSE&G had no amounts outstanding under its Commercial Paper Program as of December 31, 2017.

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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, 2017 and 2016 are included in the following table and accompanying notes as of December 31, 2017 and 2016. 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, 2017		December 31, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (A) (B)	$2,091	$2,081	$1,195	$1,185
PSE&G (B)	8,591	9,322	7,818	8,240
Power (B)	2,386	2,659	2,382	2,578
	$13,068	$14,062	$11,395	$12,003

(A) As of December 31, 2017 and 2016, fair value includes floating rate term loans of $700 million and $500 million, respectively. The fair values of the term loan debt (Level 2 measurement) approximate the carrying values because the interest payments are based on LIBOR rates that are reset monthly and the debt is redeemable at face value by PSEG at any time.

(B) Given that these bonds do not trade actively, 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.

Note 15. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2017	2016	2017	2016
	Millions			
PSEG Common Stock (no par value) (A)				
Authorized 1,000 shares	505	505	$4,198	$4,219

(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 2017 or 2016.

As of December 31, 2017, 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. Power also uses derivatives to hedge a portion of its anticipated BGSS obligations with PSE&G. For additional information see Note 13. Commitments and Contingent Liabilities. Changes in the fair market value of these 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. There were no outstanding interest rate swaps as of December 31, 2017 or 2016. The fair value hedges reduced interest expense by $6 million and $19 million for the years ended December 31, 2016 and 2015, 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. There were no outstanding interest rate hedges as of December 31, 2017. As of December 31, 2016, PSEG had interest rate hedges outstanding totaling $500 million. These hedges converted PSEG’s $500 million variable rate term loan due November 2017 into a fixed rate loan. As of December 31, 2016, the fair value of these hedges was $1 million and there was no ineffectiveness. The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was immaterial as of December 31, 2017 and $2 million as of December 31, 2016. The after-tax unrealized gains on these hedges expected to be reclassified to earnings during the next 12 months is immaterial.
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. For additional information see Note 17. Fair Value Measurements.

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

	As of December 31, 2017					
	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	$ 391	$ (362)	$ 29	$ —	$ —	$ 29
Noncurrent Assets	78	(71)	7	—	—	7
Total Mark-to-Market Derivative Assets	$ 469	$ (433)	$ 36	$ —	$ —	$ 36
Derivative Contracts						
Current Liabilities	$ (403)	$ 387	$ (16)	$ —	$ —	$ (16)
Noncurrent Liabilities	(95)	90	(5)	—	—	(5)
Total Mark-to-Market Derivative (Liabilities)	$ (498)	$ 477	$ (21)	$ —	$ —	$ (21)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$ (29)	$ 44	$ 15	$ —	$ —	$ 15

	As of December 31, 2016					
	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	$ 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

(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, 2017 and 2016. 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, 2017, and 2016, Power had net cash collateral/margin payments to counterparties of $146 million and $56 million,

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respectively. Of these net cash collateral/margin payments, $44 million as of December 31, 2017 and $1 million as of December 31, 2016 were netted against the corresponding net derivative contract positions. Of the $44 million as of December 31, 2017, $(3) million was netted against current assets, $28 million was netted against current liabilities and $19 million was netted against noncurrent liabilities. Of the $1 million as of December 31, 2016, $(3) million was netted against noncurrent assets and $4 million was netted against current liabilities.

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 $30 million and $19 million as of December 31, 2017 and 2016, respectively. As of December 31, 2017 and 2016, Power had the contractual right of offset of $13 million and $9 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 $17 million and $10 million as of December 31, 2017 and 2016, 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, 2017, 2016 and 2015.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Years Ended December 31,			Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Years Ended December 31,		
	2017	2016	2015		2017	2016	2015
	Millions				Millions		
PSEG							
Energy-Related Contracts	$ —	$ —	$ 3	Operating Revenues	$ —	$ —	$ 20
Interest Rate Swaps	—	3	—	Interest Expense	3	—	—
Total PSEG	$ —	$ 3	$ 3		$ 3	$ —	$ 20
Power							
Energy-Related Contracts	$ —	$ —	$ 3	Operating Revenues	$ —	$ —	$ 20
Total Power	$ —	$ —	$ 3		$ —	$ —	$ 20

There were no pre-tax gain (loss) recognized in income on derivatives (ineffective portion) as of December 31, 2017, 2016 and 2015.

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The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2015	$—	$ —
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	—	—
Balance as of December 31, 2016	$3	$ 2
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	(3)	(2)
Balance as of December 31, 2017	$—	$ —

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the years ended December 31, 2017, 2016 and 2015. Power’s derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts which Power has designated as NPNS, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load.

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2017	2016	2015
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$ 72	$ 230	$ 412
Energy-Related Contracts	Energy Costs	(17)	(8)	(8)
Total PSEG and Power		$ 55	$ 222	$ 404

The following table summarizes the net notional volume purchases/(sales) of open derivative transactions by commodity as of December 31, 2017 and 2016.

Type	Notional	Total	PSEG	Power	PSE&G
	Millions				
As of December 31, 2017					
Natural Gas	Dth	154	—	154	—
Electricity	MWh	(63)	—	(63)	—
Financial Transmission Rights (FTRs)	MWh	6	—	6	—
As of December 31, 2016					
Natural Gas	Dth	122	—	113	9
Electricity	MWh	(44)	—	(44)	—
FTRs	MWh	9	—	9	—
Interest Rate Swaps	U.S. Dollars	500	500	—	—

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Credit Risk
Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.
As of December 31, 2017, 99% of the net credit exposure for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives, NPNS and non-derivatives).
The following table provides information on Power's credit risk from others, net of collateral, as of December 31, 2017. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
	Millions				Millions	
Investment Grade	$329	$ 25	$ 304	1	$ 204	(A)
Non-Investment Grade	3	1	2	—	—	
Total	$332	$ 26	$ 306	1	$ 204	

(A) Represents net exposure with PSE&G.
As of December 31, 2017, collateral held from counterparties where Power had credit exposure included $1 million in cash collateral and $25 million in letters of credit.
As of December 31, 2017, Power had 152 active counterparties.
PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2017, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's BGS suppliers' credit exposure is calculated each business day. As of December 31, 2017, PSE&G had no net credit exposure with suppliers, including Power.
PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

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Note 17. Fair Value Measurements

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

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds, as well as natural gas futures contracts executed on NYMEX.

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

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity's own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of December 31, 2017, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

The following tables present information about PSEG's, PSE&G's and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2017 and December 31, 2016, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for PSE&G and Power.

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	Recurring Fair Value Measurements as of December 31, 2017				
Description	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$223	$—	$ 223	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$36	$(433)	$ 15	$ 442	$ 12
NDT Fund (D)					
Equity Securities	$1,055	$—	$ 1,053	$ 2	$ —
Debt Securities—U.S. Treasury	$314	$—	$ —	$ 314	$ —
Debt Securities—Govt Other	$270	$—	$ —	$ 270	$ —
Debt Securities—Corporate	$402	$—	$ —	$ 402	$ —
Other Securities	$92	$—	$ 92	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$25	$—	$ 25	$ —	$ —
Debt Securities—U.S. Treasury	$51	$—	$ —	$ 51	$ —
Debt Securities—Govt Other	$34	$—	$ —	$ 34	$ —
Debt Securities—Corporate	$119	$—	$ —	$ 119	$ —
Other Securities	$2	$—	$ 2	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(21)	$477	$ (8)	$ (485)	$ (5)
PSE&G					
Assets:					
Cash Equivalents (A)	$223	$—	$ 223	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$10	$—	$ —	$ 10	$ —
Debt Securities—Govt Other	$7	$—	$ —	$ 7	$ —
Debt Securities—Corporate	$24	$—	$ —	$ 24	$ —
Other Securities	$—	$—	$ —	$ —	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$36	$(433)	$ 15	$ 442	$ 12
NDT Fund (D)					
Equity Securities	$1,055	$—	$ 1,053	$ 2	$ —
Debt Securities—U.S. Treasury	$314	$—	$ —	$ 314	$ —
Debt Securities—Govt Other	$270	$—	$ —	$ 270	$ —
Debt Securities—Corporate	$402	$—	$ —	$ 402	$ —
Other Securities	$92	$—	$ 92	$ —	$ —
Rabbi Trust (D)					

Equity Securities—Mutual Funds	$6	$—	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$13	$—	$ —	$ 13	$ —
Debt Securities—Govt Other	$8	$—	$ —	$ 8	$ —
Debt Securities—Corporate	$30	$—	$ —	$ 30	$ —
Other Securities	$—	$—	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(21)	$477	$ (8)	$ (485)	$ (5)

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	Recurring Fair Value Measurements as of December 31, 2016				
Description	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$365	$—	$ 365	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$186	$(371)	$ 17	$ 533	$ 7
Interest Rate Swaps (C)	$1	$—	$ —	$ 1	$ —
NDT Fund (D)					
Equity Securities	$957	$—	$ 954	$ 3	$ —
Debt Securities—U.S. Treasury	$227	$—	$ —	$ 227	$ —
Debt Securities—Govt Other	$293	$—	$ —	$ 293	$ —
Debt Securities—Corporate	$337	$—	$ —	$ 337	$ —
Other Securities	$44	$—	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$22	$—	$ 22	$ —	$ —
Debt Securities—U.S. Treasury	$37	$—	$ —	$ 37	$ —
Debt Securities—Govt Other	$66	$—	$ —	$ 66	$ —
Debt Securities—Corporate	$91	$—	$ —	$ 91	$ —
Other Securities	$1	$—	$ 1	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(16)	$372	$ (18)	$ (364)	$ (6)
PSE&G					
Assets:					
Cash Equivalents (A)	$365	$—	$ 365	$ —	$ —
Derivative Contracts:					
Energy Related Contracts (B)	$—	$—	$ —	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$7	$—	$ —	$ 7	$ —
Debt Securities—Govt Other	$13	$—	$ —	$ 13	$ —
Debt Securities—Corporate	$18	$—	$ —	$ 18	$ —
Other Securities	$—	$—	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(5)	$—	$ —	$ —	$ (5)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$186	$(371)	$ 17	$ 533	$ 7
NDT Fund (D)					

Equity Securities	$957	$—	$ 954	$ 3	$ —
Debt Securities—U.S. Treasury	$227	$—	$ —	$ 227	$ —
Debt Securities—Govt Other	$293	$—	$ —	$ 293	$ —
Debt Securities—Corporate	$337	$—	$ —	$ 337	$ —
Other Securities	$44	$—	$ 44	$ —	$ —
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$9	$—	$ —	$ 9	$ —
Debt Securities—Govt Other	$16	$—	$ —	$ 16	$ —
Debt Securities—Corporate	$23	$—	$ —	$ 23	$ —
Other Securities	$—	$—	$ —	$ —	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(11)	$ 372	$ (18)	$ (364)	$ (1)

(A) Represents money market mutual funds.

(B) Level 1—During 2016 a net fair value of $1 million relating to energy-related contracts was transferred from Level 2 into Level 1. These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.

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

Level 3—Unobservable inputs are used for the valuation of certain contracts. See “Additional Information Regarding Level 3 Measurements” below for more information on the utilization of unobservable inputs.

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

(D) As of December 31, 2016, the fair value measurement table excludes cash of $1 million, which is part of the NDT Fund. The NDT Fund maintains investments in various equity and fixed income securities classified as “available for sale.” The Rabbi Trust maintains investments in a Russell 3000 index fund and various fixed income securities classified as “available for sale” as of December 31, 2017. The Rabbi Trust maintained investments in an S&P 500 index fund and various securities classified as “available for sale” as of December 31, 2016. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).

Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Other Securities in the NDT and Rabbi Trust Funds consist primarily of investments in Dreyfus money market funds which seek a high level of current income as is consistent with the preservation of capital and the maintenance of liquidity. To pursue its goals, the fund normally invests in a diversified portfolio of high quality, short-term, dollar-denominated debt securities and government securities. The funds’ Net Asset Value is priced and published daily. The Rabbi Trust equity index fund is valued based on quoted prices in an active market.

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

(E) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheets. As of December 31, 2017 and 2016, Power had net cash collateral/margin payments to counterparties of $146 million and $56 million, respectively. Of these net cash collateral/margin payments $44 million as of December 31, 2017 and $1 million as of December 31, 2016 were netted against the corresponding net derivative contract positions. Of the $44 million of cash collateral as of December 31, 2017, $(3) million was netted against assets, and $47 million was netted against liabilities. Of the $1 million of cash collateral as of December 31, 2016, $(3) million was netted against assets and $4 million was netted against liabilities.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in

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Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee (RMC) approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The RMC reports to the Corporate Governance and Audit Committees of the PSEG Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

For PSE&G, the natural gas supply contract is measured at fair value using modeling techniques taking into account the current price of natural gas adjusted for appropriate risk factors, as applicable, and internal assumptions about transportation costs, and accordingly, the fair value measurements are classified in Level 3. The fair value of Power's electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The fair value of Power's gas physical contracts at certain illiquid delivery locations are measured using average historical basis and, accordingly, are categorized as Level 3. While these gas physical contracts have an unobservable component in their respective forward price curves, the fluctuations in fair value have been driven primarily by changes in the observable inputs. The following tables provide details surrounding significant Level 3 valuations as of December 31, 2017 and 2016.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2017 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Load Contracts	$ 1	$ (3)	Discounted Cash flow	Historic Load Variability	0% to +10%
Gas	Gas Physical Contracts	11	(2)	Discounted Cash flow	Average Historical Basis	-40% to -10%
Total Power		$ 12	$ (5)			
Total PSEG		$ 12	$ (5)			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2016 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
PSE&G						
Gas	Natural Gas Supply Contract	$ —	$ (5)	Discounted Cash Flow	Transportation Costs	$0.60 to $0.80/Dth
Total PSE&G		$ —	$ (5)			
Power						
Electricity		$ 7	$ (1)			0% to +10%

	Electric Load Contracts				Discounted Cash Flow	Historic Load Variability
Gas (A)	Other	—	—			
Total Power		$ 7	$	(1)		
Total PSEG		$ 7	$	(6)		

(A) Includes gas positions which were immaterial.

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in the load variability would

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decrease the fair value. For gas-related contracts in cases where Power is a buyer, an increase in the average historical basis would increase the fair value.
A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the years ended December 31, 2017 and 2016, respectively, follows:
Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Year Ended December 31, 2017

		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2017	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of December 31, 2017
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$1	$ 26	$ 5	$ —	$ (24)	$ (1)	$ 7
PSE&G							
Net Derivative Assets (Liabilities)	$(5)	$ —	$ 5	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$6	$ 26	$ —	$ —	$ (24)	$ (1)	$ 7

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Year Ended December 31, 2016

		Total Gains or (Losses) Realized/Unrealized					
Description	Balance as of January 1, 2016	Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of December 31, 2016
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$13	$ 13	$ (7)	$ 3	$ (21)	$ —	$ 1
PSE&G							
Net Derivative Assets (Liabilities)	$2	$ —	$ (7)	$ —	$ —	$ —	$ (5)
Power							
Net Derivative Assets (Liabilities)	$11	$ 13	$ —	$ 3	$ (21)	$ —	$ 6

(A) PSEG's and Power's gains(losses) attributable to changes in net derivative assets and liabilities for 2017 include $14 million in Operating Revenues, of which $(9) million is unrealized and $12 million in Energy Costs, all of which is unrealized. For 2016, $25 million is included in Operating Revenues, of which $(5) million is unrealized, and $(12)

million is in Energy Costs, all of which is realized.

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

(C) Represents $(24) million and $(21) million in settlements for derivative contracts in 2017 and 2016, respectively.

(D) During the year ended December 31, 2017, $(1) million of net derivatives assets/liabilities were transferred from Level 2 to Level 3.

As of December 31, 2017, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $7 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of December 31, 2016, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $1 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Note 18. Stock Based Compensation

PSEG's Amended and Restated 2004 Long-Term Incentive Plan (LTIP) is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance share units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIP are non-qualified options to purchase shares of PSEG's common stock, restricted stock unit awards and performance share unit awards. The type of equity award that is granted and the details of that award may vary from time to time and is subject to the approval of the Organization and Compensation Committee of PSEG's Board of Directors (O&CC), the LTIP's administrative committee.

The LTIP currently provides for the issuance of equity awards with respect to approximately 16 million shares of common stock. As of December 31, 2017, there were approximately 14 million shares available for future awards under the LTIP.

Stock Options

Under the LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the O&CC. Option awards are granted with an exercise price equal to the market price of PSEG's common stock at the grant date. The options generally vest over four years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the O&CC (but not prior to one year or longer than ten years from the date of grant) and are subject to such other terms and conditions as the O&CC determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the O&CC, by delivering previously acquired shares of PSEG common stock. No options have been issued since 2009.

Restricted Stock Units

Under the LTIP, PSEG has granted restricted stock unit awards to officers and other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until distributed, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. The restricted stock unit grants for 2017 and 2016 generally vest at the end of three years. Vesting may be accelerated (pro-rated basis or full vesting) upon certain events such as retirement, disability, change-in-control or death.

Performance Share Units

Under the LTIP, PSEG has granted performance share units to officers and other key employees. These provide for payment in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. Following the end of the performance period, the payout varies from 0% to 200% of the number of performance units granted depending on PSEG's performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy companies. The performance share units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. Vesting may be accelerated on a pro-rated basis for the period of the employee's service during the performance period as a result of certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

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Stock-Based Compensation
PSEG recognizes compensation expense for stock options based on their grant date fair values, which are determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.
PSEG recognizes compensation expense for restricted stock units over the vesting period based on the grant date fair value of the shares, which is equal to the market price of PSEG's common stock on the date of the grant.
PSEG recognizes compensation expense for the total shareholder return target for its performance share unit awards based on the grant date fair values of the award, which are determined using the Monte Carlo model. The accrual of compensation cost is based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. PSEG recognizes compensation expense for the return on invested capital target for its performance share units based on the grant date fair value of the awards, which is equal to the market price of PSEG's common stock on the date of the grant. The accrual during the year of grant is estimated at 100% of the original grant. Such accrual may be adjusted to reflect the actual outcome.

	2017	2016	2015
	Millions		
Compensation Cost included in Operation and Maintenance Expense	$31	$ 29	$ 34
Income Tax Benefit Recognized in Consolidated Statement of Operations	$13	$ 12	$ 14

For 2017, 2016 and 2015 the excess tax benefit of $4 million, $4 million and $3 million, respectively was included as financing cash flows on the Consolidated Statements of Cash Flow.
PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.
Stock Options
Changes in stock options for 2017 are summarized as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding as of January 1, 2017	1,029,900	$ 37.93		
Exercised	654,200	$ 40.02		
Canceled/Forfeited	27,800	$ 44.44		
Outstanding as of December 31, 2017	347,900	$ 33.49	1.9	$6,265,679
Exercisable at December 31, 2017	347,900	$ 33.49	1.9	$6,265,679

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. There were no option grants in 2017, 2016 and 2015.
Activity for options exercised for the years ended December 31, 2017, 2016 and 2015 is shown below:

	2017	2016	2015
	Millions		
Total Intrinsic Value of Options Exercised	$5	$ 7	$ 3
Cash Received from Options Exercised	$26	$ 22	$ 12
Tax Benefit Realized from Options Exercised	$—	$ 1	$ —

No options were vested during the years ended December 31, 2017, 2016 and 2015.

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Restricted Stock Units
Changes in restricted stock units for the year ended December 31, 2017 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2017	322,196	$ 38.75		
Granted	212,158	$ 44.33		
Vested	303,092	$ 39.96		
Canceled/Forfeited	17,363	$ 41.76		
Non-vested as of December 31, 2017	213,899	$ 42.32	1.0	$ 11,015,850

The weighted average grant date fair value per share for restricted stock during the years ended December 31, 2017, 2016 and 2015 was $44.33, $42.28 and $39.65 per share, respectively.
The total intrinsic value of restricted stock units distributed during the years ended December 31, 2017, 2016 and 2015 was
$13 million, $17 million and $11 million, respectively.
As of December 31, 2017, there was approximately $3 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of ten months. Dividend equivalents units of 30,066 accrued on the restricted stock units during the year.
Performance Share Units
Changes in performance share units for the year ended December 31, 2017 are summarized as follows:

	Shares	Weighted Average Grant Date Fair Value	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Non-vested as of January 1, 2017	393,812	$ 44.20		
Granted	382,830	$ 45.02		
Vested	402,451	$ 44.03		
Canceled/Forfeited	41,730	$ 44.69		
Non-vested as of December 31, 2017	332,461	$ 45.29	1.7	$ 17,121,742

The weighted average grant date fair value per share for performance share units during the years ended December 31, 2017, 2016 and 2015 was $45.02, $45.97 and $41.32 per share, respectively.
The total intrinsic value of performance share units distributed during the years ended December 31, 2017, 2016 and 2015 was
$18 million, $17 million and $13 million, respectively.
As of December 31, 2017, there was approximately $16 million of unrecognized compensation cost related to the performance share units, which is expected to be recognized over a weighted average period of one year. Dividend equivalents units of 38,425 accrued on the performance share units during the year.
Outside Directors
Under the Directors Equity Plan, annually, on the first business day of May, each non-employee member of the Board of Directors is awarded stock units based on the amount of annual compensation to be paid at the closing price of PSEG common stock on that date. Dividend equivalents are credited quarterly and distributions will commence upon the director leaving the Board as specified by him/her in accordance with the provisions of the Directors Equity Plan. The fair value of these awards is recorded as compensation expense in the Consolidated Statements of Operations. Compensation expense for the plan was immaterial for each of the years ended December 31, 2017, 2016 and 2015.

Employee Stock Purchase Plan (ESPP)
PSEG maintains an ESPP for all eligible employees of PSEG and its subsidiaries. Under the ESPP, shares of PSEG common stock may be purchased at 95% of the fair market value for represented employees and 90% for non-represented employees through payroll deductions. Dividends will be reinvested for all employees at 95% of the fair market price unless the participant elects to receive a cash dividend. All employees are required to hold the shares purchased under the ESPP for at least three

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months from the purchase date. In any year, employees may purchase shares having a value not exceeding 10% of their base pay. Compensation expense recognized under this program was immaterial for each of the years ended December 31, 2017, 2016 and 2015.

During the years ended December 31, 2017, 2016 and 2015, employees purchased 288,527 shares, 262,763 shares and 250,499 shares at an average price of $42.07, $40.70 and $36.66 per share, respectively. As of December 31, 2017, 3.2 million shares were available for future issuance under this plan.

Note 19. Other Income and Deductions

Other Income	PSE&G	Power	Other (A)	Consolidated Total
	Millions			
Year Ended December 31, 2017				
NDT Fund Gains, Interest, Dividend and Other Income	$—	$ 202	$ —	$ 202
Allowance for Funds Used During Construction	56	—	—	56
Rabbi Trust Realized Gains, Interest and Dividends	5	6	13	24
Solar Loan Interest	21	—	—	21
Other	10	5	1	16
Total Other Income	$92	$ 213	$ 14	$ 319
Year Ended December 31, 2016				
NDT Fund Gains, Interest, Dividend and Other Income	$—	$ 96	$ —	$ 96
Allowance for Funds Used During Construction	49	—	—	49
Rabbi Trust Realized Gains, Interest and Dividends	3	3	6	12
Solar Loan Interest	22	—	—	22
Other	9	3	—	12
Total Other Income	$83	$ 102	$ 6	$ 191
Year Ended December 31, 2015				
NDT Fund Gains, Interest, Dividend and Other Income	$—	$ 138	$ —	$ 138
Allowance for Funds Used During Construction	48	—	—	48
Rabbi Trust Realized Gains, Interest and Dividends	2	2	6	10
Solar Loan Interest	23	—	—	23
Gain on Insurance Recovery	—	28	—	28
Other	6	1	—	7
Total Other Income	$79	$ 169	$ 6	$ 254

Other Deductions	PSE&G	Power	Other (A)	Consolidated Total
	Millions			
Year Ended December 31, 2017				
NDT Fund Realized Losses and Expenses	$—	$ 32	$ —	$ 32
Other	5	24	30	59
Total Other Deductions	$5	$ 56	$ 30	$ 91
Year Ended December 31, 2016				
NDT Fund Realized Losses and Expenses	$—	$ 40	$ —	$ 40
Other	4	17	6	27
Total Other Deductions	$4	$ 57	$ 6	$ 67
Year Ended December 31, 2015				
NDT Fund Realized Losses and Expenses	$—	$ 45	$ —	$ 45

Other	4	27	26	57
Total Other Deductions	$4	$ 72	$ 26	$ 102

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

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Note 20. Income Taxes
A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSEG	Years Ended December 31, 2017	2016	2015
	Millions		
Net Income	$1,574	$887	$1,679
Income Taxes:			
Operating Income:			
Current Expense (Benefit):			
Federal	$86	$(74)	$243
State	(31)	61	85
Total Current	55	(13)	328
Deferred (Benefit) Expense:			
Federal	(482)	311	540
State	92	28	104
Total Deferred	(390)	339	644
Investment Tax Credit (ITC)	29	85	29
Total Income Tax (Benefit) Expense	$(306)	$411	$1,001
Pre-Tax Income	$1,268	$1,298	$2,680
Tax Computed at Statutory Rate @ 35%	$444	$454	$938
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	36	56	129
Uncertain Tax Positions	(3)	(31)	7
Manufacturing Deduction	(13)	(17)	(10)
NDT Fund	19	3	7
Plant-Related Items	(23)	(20)	(20)
Tax Credits	(22)	(25)	(13)
Audit Settlement	6	—	—
Nuclear Decommissioning Tax Carryback	—	—	(33)
Provisional Deferred Tax Benefit - Tax Act	(755)	—	—
Other	5	(9)	(4)
Sub-Total	(750)	(43)	63
Total Income Tax (Benefit) Expense	$(306)	$411	$1,001
Effective Income Tax Rate	(24.1)%	31.7%	37.4%

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The following is an analysis of deferred income taxes for PSEG:

PSEG	As of December 31, 2017	2016
	Millions	
Deferred Income Taxes		
Assets:		
Noncurrent		
Regulatory Liability Excess Deferred Tax	$602	$—
OPEB	217	283
Related to Uncertain Tax Position	142	155
Total Noncurrent Assets	$961	$438
Liabilities:		
Noncurrent:		
Plant-Related Items	$4,257	$6,593
New Jersey Corporate Business Tax	674	674
Leasing Activities	384	565
AROs and NDT Fund	233	398
Pension Costs	123	197
Taxes Recoverable Through Future Rates (net)	80	208
Other	171	212
Total Noncurrent Liabilities	$5,922	$8,847
Summary of Accumulated Deferred Income Taxes:		
Net Noncurrent Deferred Income Tax Liabilities	$4,961	$8,409
ITC	279	249
Net Total Noncurrent Deferred Income Taxes and ITC	$5,240	$8,658

The deferred tax effect of certain assets and liabilities is presented in the table above net of the deferred tax effect associated with the respective regulatory deferrals. Also, the deferred tax effect of AROs is presented net of the deferred tax effect of the associated funding of those obligations.

In December 2017, new tax legislation was enacted, reducing the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018. PSEG is subject to ASC 740, which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate was enacted. The impact of the reduced tax rate is the primary reason for the decrease in the deferred tax liabilities.

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A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

PSE&G	Years Ended December 31, 2017	2016	2015
	Millions		
Net Income	$973	$889	$787
Income Taxes:			
Operating Income:			
Current (Benefit) Expense:			
Federal	$(52)	$(153)	$32
State	(1)	10	52
Total Current	(53)	(143)	84
Deferred Expense:			
Federal	492	551	325
State	129	102	52
Total Deferred	621	653	377
ITC	(5)	5	9
Total Income Tax Expense	$563	$515	$470
Pre-Tax Income	$1,536	$1,404	$1,257
Tax Computed at Statutory Rate @ 35%	$538	$491	$440
Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:			
State Income Taxes (net of federal income tax)	83	72	67
Uncertain Tax Positions	(9)	(18)	(14)
Plant-Related Items	(23)	(20)	(20)
Tax Credits	(9)	(7)	(6)
Provisional Deferred Tax Benefit - Tax Act	(10)	—	—
Other	(7)	(3)	3
Sub-Total	25	24	30
Total Income Tax Expense	$563	$515	$470
Effective Income Tax Rate	36.7%	36.7%	37.4%

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The following is an analysis of deferred income taxes for PSE&G:

	As of December 31,	
PSE&G	2017	2016
	Millions	
Deferred Income Taxes		