

PUBLIC SERVICE ENTERPRISE GROUP INC
 Form 10-K
 February 28, 2019

Table of Contents

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

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
 SECURITIES EXCHANGE ACT OF 1934
 FOR THE FISCAL YEAR ENDED DECEMBER 31, 2018

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.
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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
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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
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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
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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

(Cover continued on next page)

Table of Contents

(Cover continued from previous page)

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
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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 No

Public Service Electric and Gas Company Yes No

PSEG Power LLC Yes 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

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 No

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted 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 such files). Yes 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, a 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 <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>	Non-accelerated filer <input type="checkbox"/>	Smaller reporting company <input type="checkbox"/>	Emerging growth company <input type="checkbox"/>
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Public Service Electric and Gas Company	Large accelerated filer <input type="checkbox"/>	Accelerated filer <input type="checkbox"/>	Non-accelerated filer <input type="checkbox"/>	Smaller reporting company <input checked="" type="checkbox"/>	Emerging growth company <input type="checkbox"/>
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PSEG Power LLC	Large accelerated filer <input type="checkbox"/>	Accelerated filer <input type="checkbox"/>	Non-accelerated filer <input type="checkbox"/>	Smaller reporting company <input checked="" type="checkbox"/>	Emerging growth company <input type="checkbox"/>
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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

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2018 was \$27,172,268,280 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 15, 2019 was 504,999,536.

As of February 15, 2019, 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.

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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 2019 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, 2019, as specified herein.

Table of Contents

TABLE OF CONTENTS

	Page
FORWARD-LOOKING STATEMENTS	<u>iii</u>
FILING FORMAT	<u>1</u>
WHERE TO FIND MORE INFORMATION	<u>1</u>
PART I	
Item 1. Business	<u>1</u>
Regulatory Issues	<u>15</u>
Environmental Matters	<u>20</u>
Executive Officers of the Registrant (PSEG)	<u>24</u>
Item 1A. Risk Factors	<u>25</u>
Item 1B. Unresolved Staff Comments	<u>38</u>
Item 2. Properties	<u>39</u>
Item 3. Legal Proceedings	<u>40</u>
Item 4. Mine Safety Disclosures	<u>40</u>
PART II	
Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	<u>40</u>
Item 6. Selected Financial Data	<u>42</u>
Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations	<u>43</u>
Executive Overview of 2018 and Future Outlook	<u>43</u>
Results of Operations	<u>50</u>
Liquidity and Capital Resources	<u>59</u>
Capital Requirements	<u>63</u>
Off-Balance Sheet Arrangements	<u>65</u>
Critical Accounting Estimates	<u>65</u>
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	<u>69</u>
Item 8. Financial Statements and Supplementary Data	<u>71</u>
Report of Independent Registered Public Accounting Firm	<u>72</u>
Consolidated Financial Statements	<u>75</u>
Notes to Consolidated Financial Statements	
Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies	<u>93</u>
Note 2. Recent Accounting Standards	<u>98</u>
Note 3. Revenues	<u>101</u>
Note 4. Early Plant Retirements	<u>105</u>
Note 5. Variable Interest Entity	<u>107</u>
Note 6. Property, Plant and Equipment and Jointly-Owned Facilities	<u>107</u>
Note 7. Regulatory Assets and Liabilities	<u>109</u>
Note 8. Long-Term Investments	<u>113</u>
Note 9. Financing Receivables	<u>115</u>
Note 10. Trust Investments	<u>116</u>
Note 11. Goodwill and Other Intangibles	<u>121</u>
Note 12. Asset Retirement Obligations (AROs)	<u>122</u>
Note 13. Pension, Other Postretirement Benefits (OPEB) and Savings Plans	<u>123</u>
Note 14. Commitments and Contingent Liabilities	<u>132</u>
Note 15. Debt and Credit Facilities	<u>140</u>
Note 16. Schedule of Consolidated Capital Stock	<u>144</u>

Table of Contents

TABLE OF CONTENTS (continued)	
Note 17. Financial Risk Management Activities	<u>145</u>
Note 18. Fair Value Measurements	<u>149</u>
Note 19. Stock Based Compensation	<u>155</u>
Note 20. Other Income (Deductions)	<u>158</u>
Note 21. Income Taxes	<u>159</u>
Note 22. Accumulated Other Comprehensive Income (Loss), Net of Tax	<u>168</u>
Note 23. Earnings Per Share (EPS) and Dividends	<u>172</u>
Note 24. Financial Information by Business Segment	<u>173</u>
Note 25. Related-Party Transactions	<u>175</u>
Note 26. Selected Quarterly Data (Unaudited)	<u>176</u>
Note 27. Guarantees of Debt	<u>178</u>
Item 9. Changes In and Disagreements With Accountants on Accounting and Financial Disclosure	<u>181</u>
Item 9A. Controls and Procedures	<u>181</u>
Item 9B. Other Information	<u>181</u>
PART III	
Item 10. Directors, Executive Officers and Corporate Governance	<u>186</u>
Item 11. Executive Compensation	<u>187</u>
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	<u>187</u>
Item 13. Certain Relationships and Related Transactions, and Director Independence	<u>187</u>
Item 14. Principal Accounting Fees and Services	<u>187</u>
PART IV	
Item 15. Exhibits, Financial Statement Schedules	<u>188</u>
Schedule II - Valuation and Qualifying Accounts	<u>194</u>
Signatures	<u>195</u>

Table of Contents

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 14. 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;
- PSE&G's proposed investment programs may not be fully approved by regulators and its capital investment may be lower than planned;
- 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, and PSE&G's ability to recover costs and earn returns on authorized investments;
- the impact of any future rate proceedings;
- risks associated with our ownership and operation of nuclear facilities, including regulatory risks, such as compliance with the Atomic Energy Act and trade control, environmental and other regulations, as well as financial, environmental and health and safety risks;
 - the impact on our New Jersey nuclear plants of the failure of such plants to be selected to participate in the Zero Emissions Certificate (ZEC) program or adverse changes to the capacity market construct;
- 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;

Table of Contents

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, obtain regulatory approval for, 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;

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.

Table of Contents

FILING FORMAT

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.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may 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 trading symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 11 Wall 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

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.

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.

Also invests in regulated solar generation projects and regulated energy efficiency and related programs in New Jersey.

Power

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 the generation and marketing of power and natural gas to hedge business risks and optimize the value of its portfolio of power plants, other contractual arrangements and oil and gas storage facilities. This is achieved primarily by selling power and transacting in natural gas and other energy-related products, on the spot market or using short-term or long-term contracts for physical and financial products.

Also earns revenues from solar generation facilities under long-term sales contracts for power and environmental products.

Table of Contents

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 (T&D) 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.

Products and Services

Our utility operations primarily earn margins through the T&D 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

Table of Contents

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 is 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 our service territory.

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.

How PSE&G Operates

We are a transmission owner in PJM Interconnection, L.L.C. (PJM) and we provide distribution service to 2.3 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 densely 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 trueed 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.

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 spending of \$3.4 billion for transmission in 2019-2021 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. In October 2018, the BPU issued an Order approving the settlement of our distribution base rate proceeding with new rates effective November 1, 2018. The Order provides for a distribution rate base of \$9.5 billion, a 9.60% ROE for our distribution business and a 54% equity component of our capitalization structure. 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. Our load requirements are split among residential, commercial and industrial customers, as described in the following table for 2018:

Customer Type	% of 2018	
	Electric	Gas
Commercial	58%	38%
Residential	33%	58%
Industrial	9%	4%
Total	100%	100%

Table of Contents

Our customer base has modestly increased since 2014, with electric and gas loads increasing as illustrated below:

Electric and Gas Distribution Statistics

December 31, 2018		Historical Annual Load Growth 2014-2018	
Number of Electric Sales and Firm Gas Customers	Sales (A)		
Electric	2.3 Million	41,889 Gigawatt hours (GWh)	0.3%
Gas	1.8 Million	2,630 Million Therms	1.7%

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

Electric sales were essentially flat with increases due to growth in the number of customers and improved economic conditions offset by conservation and more energy efficient appliances. Firm gas sales increased as a result of growth in the number of customers and customer response to continued low gas prices. Only firm gas sales impact margin. PSE&G completed its BPU-approved Energy Strong Program I (ES I) in 2018. Under ES I, PSE&G, at an investment of \$1 billion, completed the replacement and modernization of 240 miles of low-pressure cast iron gas mains in or near flood areas. PSE&G upgraded all of its electric substations that were damaged by water in recent storms; made investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deployed technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage. Concerning PSE&G's gas system, PSE&G upgraded five natural gas metering stations, two liquefied propane stations and a liquefied natural gas station affected by severe weather or located in flood zones. In 2018, PSE&G also essentially completed its Gas System Modernization Program (GSMP I), which was approved by the BPU in late 2015. By June 2019, through GSMP I, we will have invested approximately \$900 million to replace approximately 450 miles of cast iron and unprotected steel gas mains and about 40,000 unprotected steel service lines to homes and businesses, including uprating of the mains to higher pressure. The mains and service lines were replaced with stronger, more durable plastic piping, reducing the potential for leaks and release of methane gas. The new elevated pressure system also includes the installation of excess flow valves on each gas service that automatically shut off gas flow if a service line is abruptly damaged, and better supports the use of high-efficiency appliances.

In May 2018, PSE&G received approval for the Gas System Modernization Program II (GSMP II), an expanded, five-year program to invest \$1.9 billion over five years beginning in 2019 to replace approximately 875 miles of cast iron and unprotected steel mains in addition to other improvements to the gas system.

In June 2018, we filed for our Energy Strong Program II (ES II), a proposed five-year \$2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient. The size and duration of ES II, as well as certain other elements of the program, are subject to BPU approval. A procedural schedule has been issued with the review process expected to conclude in mid-2019.

In October 2018, we filed our proposed Clean Energy Future (CEF) program with the BPU, a six-year estimated \$3.6 billion investment program covering four programs; (i) an Energy Efficiency (EE) program totaling \$2.5 billion of investment designed to achieve energy efficiency targets required under New Jersey's Clean Energy law; (ii) an Electric Vehicle (EV) infrastructure program; (iii) an Energy Storage (ES) program and (iv) an Energy Cloud (EC) program which will include installing approximately two million electric smart meters and associated infrastructure. The procedural process for the CEF-EE program is expected to conclude by the third quarter of 2019. The CEF-EV/ES and CEF-EC programs will have separate procedural schedules. For additional information regarding the New Jersey Division of Rate Counsel's motions related to these programs, see Item 7. MD&A—Executive Overview of 2018 and Future Outlook.

Solar Generation

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® 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.

Table of Contents

Supply

Although commodity revenues make up almost 39% 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 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 commercial and industrial (C&I) 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).

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. Note 14. 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. Note 7. Regulatory Assets and Liabilities. 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. C&I 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 fluctuations 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.

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 (FPA) 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).

Table of Contents

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 thereafter the contract remains in effect 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. Power also owns and operates 414 MW direct current (dc) of PV solar generation facilities and has an additional 52 MW dc of PV solar generation in construction. 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 (11,458 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 the Bridgeport Harbor 5 (BH5) project currently under construction:

Table of Contents**Generation Capacity**

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels. As of December 31, 2018, our fuel mix was comprised of 51% gas, 32% nuclear, 10% 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 2018 was approximately 55,800 gigawatt hours (GWh). The generation mix by fuel type in recent years has reflected the relatively more favorable price of natural gas compared to coal. The following table indicates the proportionate share of generating output by fuel type in 2018.

Generation by Fuel Type (A)	Actual 2018	
Nuclear:		
New Jersey facilities	37%	
Pennsylvania facilities	19%	
Fossil:		
Natural Gas and Oil:		
New Jersey facilities	21%	
New York facilities	9%	
Maryland facilities	4%	
Connecticut facilities	—%	(B)
Coal:		
Pennsylvania 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.

In mid-2018, we commenced commercial operations of our Keys Energy Center (Keys), a 761 MW gas-fired combined cycle generating station in Maryland and Sewaren 7, a 538 MW dual-fueled combined cycle generating station in New Jersey.

In July 2018, Exelon, co-owner of the Peach Bottom nuclear facilities in Pennsylvania, submitted a second 20-year license renewal application with the Nuclear Regulatory Commission (NRC) for Peach Bottom Units 2 and 3. It is anticipated that the NRC's review process will take approximately two years from submission of the application. Peach Bottom Units 2 and 3 are currently licensed to operate through 2033 and 2034, respectively.

In February 2016, the proposed generating facility, BH5, a 485 MW dual-fueled combined cycle generation project, was awarded a capacity obligation. Construction continues on BH5, which is targeted for commercial operation in mid-2019.

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 2018, the base load capacity factors for the following units were:

Table of Contents

Unit	2018 Capacity Factor
Nuclear	
Salem Unit 1	97.9%
Salem Unit 2	84.6%
Hope Creek	88.8%
Peach Bottom Unit 2	93.4%
Peach Bottom Unit 3	94.2%
Coal	
Keystone	83.4%
Conemaugh	76.9%

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, enabling some gas-fired generation to displace some generation by other fuel types. 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 gross margins 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.

Table of Contents

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 2018 they accounted for approximately 70% 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:

- p**urchase of uranium (concentrates and uranium hexafluoride),
- c**onversion of uranium concentrates to uranium hexafluoride,
- e**nrichment of uranium hexafluoride, and
- f**abrication of nuclear fuel assemblies.

Table of Contents

Coal Supply—The Keystone, Conemaugh and Bridgeport Harbor 3 (BH3) stations operate on coal. Coal is delivered to these units through a combination of rail, truck, barge and ocean shipments.

To control emissions levels, our BH3 unit uses a specific type of coal obtained from Indonesia. We have coal inventory at the BH3 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 Bethlehem Energy Center (BEC) in New York and hold year-round firm gas transportation to serve the majority of the requirements of Keys in Maryland.

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 New Jersey generation fleet.

Power has contracted for approximately 125,000 dekatherms/day of delivery capability on the PennEast Pipeline from eastern Pennsylvania to New Jersey. This delivery capability will be used to supplement the BGSS contract when it becomes operational.

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 a 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 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 2018 and Future Outlook and Item 8. Note 14. 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 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 on 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 several 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

10

Table of Contents

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

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

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

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 in Pennsylvania 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. The average capacity prices that Power expects to receive from the base and incremental auctions which have been completed are disclosed in Item 8. Note 3. Revenues. 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 disclosed in Note 3. Revenues due to the import and export capability to and from lower-priced areas.

We have obtained price certainty for our PJM capacity through May 2022 and New England capacity through May 2026 for BH5 and May 2022 for New Haven 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 impacting the capacity auction or 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 the stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West or other nodes within PJM corresponding to our generation portfolio and (2) BGS and similar full-requirements contracts. Sales in PJM generally reflect block energy sales at the liquid PJM Western Hub or other basis locations when available 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

Table of Contents

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)	2016-2019	2017-2020	2018-2021	2019-2022
PSE&G	\$96.38	\$90.78	\$91.77	\$98.04
Jersey Central Power & Light Company (JCP&L)	\$74.85	\$69.08	\$73.11	\$77.15
Atlantic City Electric Company	\$82.14	\$75.49	\$81.23	\$87.40
Rockland Electric Company	\$85.02	\$80.50	\$85.94	\$88.03

Although we enter into these hedges 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 C&I 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.

Reflecting February 2019 BGS auction results, the contracted percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2021 are as follows:

Base Load Generation	2019	2020	2021
Generation Sales	100%	95%-100%	30%-35%

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 2021.

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 more efficient load following units can be estimated with a moderate degree of certainty. The peaking units are 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. The natural gas-fired units are hedged based on their expected generation; however, at much lower thresholds than baseload generation.

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 2019 relates to our hedging strategy, our expected revenues from the capacity market mechanisms described above and certain ancillary service payments such as reactive power.

12

Table of Contents

Energy Holdings Lease Investments

Energy Holdings primarily owns and manages a portfolio of domestic lease investments. The majority of Energy Holdings' \$540 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2018, the counterparties for 55% of our total leveraged lease investments were rated below investment grade by Standard & Poor's (S&P). See Item 8. Note 9. 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. Note 9. Financing Receivables.

LIPA Operating Services Agreement (OSA)

In accordance with a twelve year Amended and Restated 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. Under 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. Also, there is an 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. Further, since January 2015, Power provides fuel procurement and power management services to LIPA under separate agreements.

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. 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.

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" 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 rules continue to evolve 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.

Table of Contents

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. For example, 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 but it may have an impact on Power's generation portfolio. For additional information, see the discussion in Regulatory Issues—Federal Regulation.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO₂) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states.

While it is our expectation that continued efforts may be undertaken by the federal and state governments to preserve the existing base nuclear generating plants, we still believe that pressures from renewable resources will continue to increase.

EMPLOYEE RELATIONS

As of December 31, 2018, we had 13,145 employees within our subsidiaries, including 8,145 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, 2018

PSE&G Power	PSEG LI	Services
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Non-Union	2,003	1,057	899	1,041
Union	5,315	1,065	1,510	255
Total Employees	7,318	2,122	2,409	1,296

Table of Contents

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 8. Note 14. 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 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

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 determine 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.

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. Certain reforms, such as a reform that

15

Table of Contents

would allow prices to better reflect scarcity conditions in which short-term demand is met by fast-start resources, are currently pending before FERC. However, we cannot predict whether they will be adopted.

In February 2019, the PJM Board approved a filing to modify the curves used for pricing reserves with FERC. The reforms include a 30-minute reserve product in real-time, more dynamic reserve requirements to better capture operator actions taken to maintain reliability, and improvement to the curves used to price reserves during reserve shortage conditions. If placed into effect, this reform is expected to improve energy and reserve prices by ensuring that when operators commit resources to ensure reliability, the commitments are reflected in market clearing prices. However, this reform could result in lower capacity payments. There is no timeline for this type of filing and therefore we cannot predict when FERC will act on the filing or 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. In June 2018, FERC issued an order finding that PJM's current capacity market construct was not just and reasonable. FERC found that the RPM market design was not sufficiently competitive because it enabled state-supported resources to bid below their costs which resulted in suppressed clearing prices. In particular, FERC found that nuclear generating units that receive zero emission certificate (ZEC) payments were of concern. FERC initiated a separate proceeding to develop a mechanism to protect resources that do not receive subsidies and proposed a Fixed Resource Alternative option that removes subsidized resources along with a commensurate amount of load. PSEG and other parties have sought rehearing of FERC's order, which is still pending.

In response to FERC's order, PJM proposed a minimum offer price rule (MOPR) with a significant number of exceptions and a "resource carve-out" (RCO) option that would carve certain resources out of the capacity market that have actionable subsidies. If this proposal is ultimately adopted by FERC and our New Jersey nuclear units receive ZECs, they may become subject to the MOPR and would be required to submit capacity bids at a level that may be above the auction clearing price. Under this scenario, if Hope Creek, Salem 1 and Salem 2 nuclear units are awarded ZECs, they may not clear the capacity auction in whole or in part, and they may not receive capacity payments. However, these units may be eligible for the RCO option and receive payments directly from New Jersey Load-serving entities through a mechanism approved by the BPU. The BPU could utilize the existing BGS mechanism for this purpose.

PJM also proposed an alternative to the RCO option that includes a two-tiered "repricing" option. Under this proposal, PJM would run an initial auction to determine which resources would receive a commitment and a second auction to determine the price to pay the capacity resources. If this mechanism was adopted by FERC, it would likely have a favorable impact on the capacity payments received by non-nuclear units within the PSEG generating fleet but could adversely affect the nuclear units if, as ZEC recipients, they participate as RCO resources and have to make payments to other plants. We are unable to predict the outcome of the FERC proceeding or any BPU efforts to effectuate the RCO option.

In October 2018, PJM filed with FERC to revise the shape of the Variable Resource Requirement (VRR) curve that will be implemented for the capacity auction that will be held in August 2019. The VRR curve is the administratively determined demand curve that serves as one of the key elements for establishing the amount of generation capacity to be procured in the auction. PJM contends that its proposal will lower capacity prices as compared to the currently

effective VRR curve. PSEG protested PJM's proposal on the grounds that it would result in understated prices for capacity relative to the cost of constructing a new reference generating unit and will result in prices that are unjust and unreasonable. This matter is pending before FERC and we cannot predict the outcome.

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 Capacity Performance 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. In March 2018, FERC approved proposed changes to the FCM referred to as the

Table of Contents

Competitive Auctions and Sponsored Policy Resources (CASPR) 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 phases out the exemption from the MOPR in the capacity market afforded for up to 200MW annually (600 MW cumulatively) of renewable resources, an aspect of the market design that we did not support due to the capacity market suppression associated with this mechanism. The effective date of these CASPR provisions will be implemented beginning with the Forward Capacity Auction to be held in February 2019.

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, which was denied by FERC at the end of 2017. 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” 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 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.

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 tried up to reflect actual annual expenses and capital expenditures.

For additional information about our transmission filings, see Item 8. Note 7. Regulatory Assets and Liabilities.

Transmission Policy Developments—There are several matters pending before FERC that concern the allocation of costs associated with transmission projects contending that insufficient levels of costs are being allocated to customers in the PSE&G transmission zone. Projects involved include the Artificial Island project and the Bergen-Linden Corridor project in New Jersey. In April 2016, FERC issued orders denying the complaints and leaving the current cost allocation in effect as to the Bergen-Linden project. In October 2017, FERC accepted the Artificial Island Cost allocation 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. It is anticipated that additional proceedings are likely to occur.

Another proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kilovolt (kV) projects in PJM that either have been built or are in the process of being built. In May 2018, FERC approved a settlement for this matter that is expected to result in increased annual cost allocations to customers in the PSE&G transmission zone. The cost reallocation was implemented by PJM in July 2018. Under this settlement, Power, as a BGS supplier is obligated to pay amounts previously paid by other PJM transmission customers. In November 2018, the BPU authorized BGS suppliers to collect increased allocation amounts from BGS customers through a pass-through provision in the BGS supplier contracts.

Transmission Rate Proceedings and Return on Equity—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 proposed changes to the ROE calculation methodology discussed below, create some uncertainty as to the timing and outcome of these complaints. The results of these settlements and proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

In October 2018, FERC issued an order establishing a new framework for determining whether a company's ROE is unjust and unreasonable. The order was issued in a proceeding that was remanded to FERC from D.C. Circuit concerning the

Table of Contents

establishment of the New England Transmission Owners' ROE. FERC's order proposes a new method for evaluating whether an existing ROE remains just and reasonable. Under FERC's approach, FERC will determine a composite zone of reasonableness based on the results of three financial models, and if the targeted utility's existing ROE falls within the range of just and reasonable ROEs for its risk profile, FERC will dismiss the complaint. However, if FERC determines that an existing ROE is unjust and unreasonable, it proposes to rely on four financial models: a discounted cash flow, a risk premium analysis, a capital-asset pricing model analysis and an expected earnings analysis. We are analyzing the potential impact of these methodologies and cannot predict the outcome of this proceeding.

Compliance

Reliability Standards—Congress has required FERC to put in place, through the North American Electric Reliability Corporation (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 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 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 (CIP) 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 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 Nuclear Regulatory Commission (NRC), a federal agency established to regulate nuclear activities to ensure the 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 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 the 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.

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 proceedings. Recovery of these costs or investments is subject to BPU approval for

Table of Contents

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. Note 7. Regulatory Assets and Liabilities.

New Jersey Energy Master Plan (EMP)—In May 2018, the New Jersey governor signed an executive order directing the BPU and other New Jersey executive branch agencies to prepare a new EMP by June 1, 2019. While not having the force of law, the EMP provides an overview of energy policy in New Jersey. The new EMP will, among other issues: focus on New Jersey converting to 100% clean energy sources by January 1, 2050; incorporate New Jersey's offshore wind development goals; include provisions to guide the continued development of solar energy, including community solar; make recommendations to bolster energy storage in New Jersey; and explore methods to incentivize the use of clean, efficient energy and electric technology alternatives in New Jersey's transportation sector and at its ports.

In January 2018, the governor of New Jersey signed Executive Order No. 8 directing the BPU to begin the process of moving the state toward its 2030 goal of 3,500 MW of offshore wind energy generation. An initial solicitation was established for 1,100 MW of offshore wind, with bids due in December 2018. For a discussion of our involvement with offshore wind in New Jersey, see Item 7. MD&A—Executive Overview of 2018 and Future Outlook.

Energy Efficiency Initiatives—In May 2018, the New Jersey governor signed legislation that requires the state's electric and gas utilities to implement energy efficiency programs that are expected to achieve energy savings targets for electric and gas usage within five years of the utility's implementation of its BPU-approved energy efficiency programs. To meet these savings targets, energy usage reductions and peak demand reductions that result from utility and non-utility based programs and investments (including building code changes) will be counted. The initial targets are 2% of annual electric usage and 0.75% of annual gas usage with the targets then being reassessed periodically by the BPU. The specific energy savings target for each public electric and gas utility will be determined from an energy efficiency study to be completed within a year from enactment of the legislation. The legislation requires utilities to make annual filings with the BPU outlining their planned investments and proposed programs for cost-effectively achieving the targeted energy savings. These filings are also expected to address the utility's return of and on those investments and recovery of lost revenues associated with the lower sales. The BPU is required to adopt rules to implement the legislation within one year of enactment.

Infrastructure Investment Program (IIP)—The BPU has enacted IIP regulations that encourage 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.

BGSS Process—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. In March 2018, the RESA filed an amended petition with the BPU requesting a formal proceeding to establish a gas capacity release program. This filing applies to all New Jersey gas utilities. The matter remains pending.

BPU 2018 Storm Investigation—The BPU conducted an investigation of the state's EDCs' responses to the March 2018 late winter storms. Based on the findings of the investigation, the BPU implemented certain recommendations that it deemed essential to facilitate the continued provision of safe, proper and adequate service; to help mitigate future outages; and to help develop more effective responses and coordination of resources. These recommendations imposed several specific follow-up requirements on the EDCs concerning, among other things, weather forecasting; updates to the EDCs' event level classification matrices and emergency operations plans; and submission of a plan and cost benefit analysis for the implementation of Advanced Metering Infrastructure (AMI).

In January 2019, PSE&G filed a response to the request for a plan and cost benefit analysis for the implementation of AMI. The response highlighted a number of customer and operational benefits associated with the deployment of AMI, and incorporated PSE&G's EC Business case and direct testimony from the CEF-EC proceeding previously filed

with the BPU. PSE&G has filed all responses to the follow-up requirements specified by the BPU.

Federal Tax Legislation —As a result of the enactment of the Tax Cuts and Jobs Act of 2017 (Tax Act), various state regulatory authorities, including the BPU, took action to ensure that excess federal income taxes previously collected in rates are returned to customers. We have adjusted our revenue requirement in certain of our rate matters as a result of the change in the federal income tax rate.

Additional matters and information on our specific filings are discussed in Item 8. Note 7. Regulatory Assets and Liabilities.

Table of Contents

Cybersecurity

In an effort to reduce the likelihood and severity of cybersecurity incidents, we have established a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of our company's and our customers' information and our systems. 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; cybersecurity awareness throughout our company with electronic notices and seminars; and periodically reviewing industry best practices and operational benchmarking. Cybersecurity and the effectiveness of our cybersecurity processes are discussed by senior management and at Board and Audit Committee meetings. Our strategy for managing cyber-related risks is integrated within our enterprise risk management processes.

In addition, we are subject to federal and state requirements designed to further protect against cybersecurity threats to critical infrastructure, as discussed below. For a discussion of the risks associated with cybersecurity threats, see Item 1A. Risk Factors.

Federal—NERC, at the direction of FERC, has implemented national and regional reliability standards to ensure the reliability of the grid and to prevent major system blackouts. NERC CIP standards establish cybersecurity and physical security protections for critical systems and facilities. These standards are also designed to develop coordination, threat sharing and interaction between utilities and various government agencies regarding potential cybersecurity and physical threats against the nation's electric grid.

FERC further directed 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. FERC approved these supply chain risk management standards in October 2018, with an implementation date of July 1, 2020. We are taking steps to meet these additional obligations. Compliance with these new standards would be expected to impose additional costs.

State—The BPU requires utilities, including PSE&G, to, among other things, 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.

Additional requirements of this order include, but are not limited to: (i) annually inventorying critical utility systems; (ii) annually assessing risks to critical utility systems; (iii) implementing controls to mitigate cyber risks to critical utility systems; (iv) monitoring log files of critical utility systems; (v) reporting cyber incidents to the BPU; and (vi) establishing a cybersecurity incident response plan and conducting biennial exercises to test the plan.

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 and Item 8. Note 14. Commitments and Contingent Liabilities.

20

Table of Contents

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 (HAPS) 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. The 2016 Supplemental Finding determined that HAPS from existing electric generating units should be regulated and that the environmental and health benefits derived from the reduction in emissions of both HAPS and co-benefit pollutants far outweighed the cost of compliance. Industry participants and various state authorities 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.

In December 2018, the EPA issued a proposed Supplemental Finding to reverse the 2016 Supplemental Finding, concluding that the analysis should not include the benefits from the reduction in emissions from co-benefit pollutants. Although the EPA proposed that it will retain the emission standards and other requirements of MATS, it is seeking comment on two alternatives to potentially rescind MATS. Finally, the EPA proposal concluded that no additional regulations are required. We do not expect this Supplemental Finding, if finalized as proposed, to impact the operation of our facilities.

Climate Change

CO₂ 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 CO₂ 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.

In August 2018, the EPA released the proposed Affordable Clean Energy (ACE) rule as a replacement for the CPP. The proposed ACE rule gives states great flexibility to evaluate specific heat rate improvement technologies and practices to be applied at coal-fired electric generating units. States have three years from the date of finalization to submit a plan that establishes a standard of performance that reflects the degree of emission limitation through the application of heat rate improvement technologies and practices. We cannot estimate the impact of this action on our business or results of operations.

Regional Greenhouse Gas Initiative (RGGI)—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO₂ 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 CO₂ emissions. These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO₂ emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or secondary markets.

In September 2017, the RGGI States announced their new post-2020 program for a cap on regional CO₂ emissions, which would require a decline in CO₂ emissions in 2021 and each year thereafter, resulting in a 30% reduction in the

CO₂ 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 December 2018, the NJDEP proposed two rules that begin New Jersey's re-entry into RGGI. The first proposal is the mechanism that establishes New Jersey's initial cap on GHG emissions of 18 million tons in 2020. The proposal follows the RGGI model rule with a cap that will decline three percent annually through 2030 to a final cap of 11.5 million tons. New Jersey is committed to a start date of January 1, 2020. The second proposal establishes the framework for how New Jersey will

Table of Contents

spend the RGGI auction proceeds. 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. Note 14. Commitments and Contingent Liabilities for additional information.

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. 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. Note 14. 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.

Table of Contents

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 United States Department of Energy (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.

Table of Contents

EXECUTIVE OFFICERS OF THE REGISTRANT (PSEG)

Name	Age as of December 31, 2018	Office	Effective Date First Elected to Present Position
Ralph Izzo	61	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	55	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	57	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 A. LaRossa	55	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	54	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

<p>Tamara L. Linde</p>	<p>54</p>	<p>Executive Vice President and General Counsel (PSEG) Executive Vice President and General Counsel (PSE&G) Executive Vice President and General Counsel (Power) Vice President - Regulatory (Services)</p>	<p>July 2014 to present July 2014 to present July 2014 to present December 2006 to July 2014</p>
<p>Stuart J. Black</p>	<p>56</p>	<p>Vice President and Controller (PSEG) Vice President and Controller (PSE&G) Vice President and Controller (Power) Vice President (Services) and Assistant Controller (Power)</p>	<p>August 2014 to present August 2014 to present August 2014 to present March 2010 to August 2014</p>

Table of Contents

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.

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

We obtain substantially all of our physical natural gas 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 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.

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

25

Table of Contents

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 2018, a petition was filed with the U.S. Department of Commerce by two uranium mining companies seeking relief under Section 232 of the Trade Expansion Act of 1962, as amended, from imports of uranium products, alleging that these imports threaten national security. In July 2018, the Secretary of Commerce announced the initiation of an investigation in response to the petition. The relief sought by the petitioners would require U.S. nuclear reactors to purchase at least 25% of their uranium needs from domestic mines over the next ten years, although the Department of Commerce and ultimately the President will make an independent determination regarding an appropriate remedy regarding uranium imports and national security. The outcome of this petition could increase nuclear fuel costs in future periods, which would have an adverse impact on the results of operations, cash flows and financial positions of our nuclear facilities.

Although our fuel contract portfolio provides a degree of hedging against these market risks, such hedging may not be effective and future increases in our fuel costs could materially and adversely affect our liquidity, financial condition and results of operations. While our generation runs on a mix of fuels, primarily natural gas and nuclear fuel, an increase in the cost of any particular fuel ultimately used could impact our results of operations.

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

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

Factors that may cause market price fluctuations include:

- increases and decreases in generation capacity, including the addition of new supplies of power as a result of the development of new power plants, expansion of existing power plants or additional transmission capacity;
- power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including power plant outages and transmission disruptions;
- weather conditions, particularly unusually mild summers or warm winters in our market areas;
- quarterly and seasonal fluctuations;
- economic and political conditions that could negatively impact the 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 or if our internal policies and procedures designed to monitor the exposure to these various risks are 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.

PSE&G's proposed investment programs may not be fully approved by regulators, which could result in lower than desired service levels to customers, and actual capital investment by PSE&G may be lower than planned, which would cause lower than anticipated rate base.

PSE&G is a regulated public utility that operates and invests in an electric T&D system and a gas distribution system as well as certain regulated clean energy investments, including solar and energy efficiency within New Jersey.

PSE&G invests in capital projects to maintain and improve its existing T&D system and to address various public policy goals and meet customer

Table of Contents

expectations. Transmission projects are subject to review in the FERC-approved PJM transmission expansion process while distribution and clean energy projects are subject to approval by the BPU. We cannot be certain that any proposed project will be approved as requested or at all. In particular, PSE&G is currently seeking approval for a number of investment programs from the BPU including our ES II, a proposed five-year \$2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient; and our proposed CEF program, a six-year estimated \$3.6 billion investment program focused on achieving New Jersey's EE targets, supporting EV infrastructure, deploying ES, and implementing an EC program. If these programs and other programs that PSE&G may file from time to time are only approved in part, or not at all, or if the approval fails to allow for the timely recovery of all of PSE&G's costs, including a return of, or on, its investment, PSE&G will have a lower than anticipated rate base, thus causing its future earnings to be lower than anticipated. If these programs are not approved, that could also adversely affect our service levels for customers. Further, the BPU could take positions to exclude or limit utility participation in certain areas, such as renewable generation, energy efficiency, electric vehicle infrastructure and energy storage, which would limit our relationship with customers and narrow our future growth prospects.

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 and cash flows.

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 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. 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 also 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. These technologies could also result in further declines in commodity prices or demand for delivered energy.

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

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

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices for power, generation capacity and natural gas, which can fluctuate substantially. Increased unemployment of residential customers and decreased demand for products and services provided by C&I customers resulting from an economic downturn could lead to declines in the demand for energy and an increase in the number of uncollectible

Table of Contents

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 of these counterparties to perform 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 (NDT) Fund 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 NDT Fund 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 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 NDT Fund 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 proceeding and remain in effect until a new base rate proceeding is filed and concluded. 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 prudence 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 proceeding to adjust revenue requirements or seek recovery through 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 material 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

Table of Contents

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 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 proceedings with the BPU. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for PSE&G to recover its costs by the time the rates become effective. Established rates are also subject to subsequent reviews by state regulators, whereby various portions of rates could be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, manufactured gas plant (MGP) remediation, smart grid infrastructure and energy efficiency, demand response and renewable energy programs. If future base rate proceedings are protracted or result 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.

NERC Compliance—NERC, at the direction of FERC, has implemented mandatory NERC Operations and CIP standards to ensure the reliability of the U.S. Bulk Electric System, which includes electric transmission and generation systems, and to prevent major system black-outs. NERC CIP standards establish cybersecurity and physical security protections for critical systems and facilities. 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. An audit of PSE&G's compliance with CIP physical and cybersecurity standards was performed in the fourth quarter of 2018, the results of which are under review. We cannot determine what actions, if any, NERC or FERC may take. 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.

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.

Oversight by the 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

Table of Contents

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 risks as well as financial, environmental and 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. In addition to the risk of retirement discussed below, risks associated with the operation of nuclear facilities 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, trade controls 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, trade controls 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 unit 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 an industry nuclear incident or retrospective premiums due to adverse industry loss experience and such assessments may be material.

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 an NDT Fund 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 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 Fund continues to satisfy the NRC minimum funding requirements. As a result, our financial position or cash flows could be significantly adversely affected.

Table of Contents

There is no assurance that our New Jersey nuclear plants will be selected to participate in the Zero Emission Certificate (ZEC) program. Absent a material financial change, failure of any of these plants to be selected would result in the retirement of all of these nuclear plants.

In May 2018, the governor of New Jersey signed legislation, referred to as the ZEC legislation, that recognizes that nuclear power is a critical component of New Jersey's clean energy portfolio and an important element of a diverse energy generation portfolio that currently meets approximately 40 percent of New Jersey's electric power needs. The ZEC legislation creates a ZEC program to be administered by the BPU.

In December 2018, Power submitted applications to the BPU for the Salem 1 and 2 and Hope Creek nuclear plants. As required, Power's three applications each included a certification pursuant to which Power confirmed that each of the Salem 1, Salem 2 and Hope Creek plants will cease operations within three years absent a material financial change. Power's submittal further attested that the nuclear plants are not expected to cover their costs and operating and market risks as defined in the ZEC legislation, absent a material financial change.

In the event that any of the Salem 1, Salem 2 and Hope Creek plants is not selected to receive ZEC payments in April 2019 by the BPU and do not otherwise experience a material financial change, Power will take all necessary steps to retire all of these plants at or prior to their refueling outages scheduled for the Fall 2019 in the case of Hope Creek, Spring 2020 in the case of Salem 2 and Fall 2020 in the case of Salem 1. Alternatively, if all of the Salem 1, Salem 2 and Hope Creek plants are selected to receive ZEC payments in April 2019 but the financial condition of the plants is materially adversely impacted by potential changes to the capacity market construct being considered by FERC (absent sufficient capacity revenues provided under a program approved by the BPU in accordance with a FERC authorized capacity mechanism), Power would still take all necessary steps to retire all of these plants. The costs and accounting charges associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, potential penalties associated with the early termination of capacity obligations and fuel contracts, accelerated asset retirement costs, severance costs, environmental remediation costs and, in certain circumstances, potential additional funding of the NDT Fund, would be material to both PSEG and Power.

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 FCM 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 how we conduct our operations and make capital expenditures. There have been a number of recent changes to existing environmental laws and regulations and this trend may continue. 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.

31

Table of Contents

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 CO₂ 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 2018 the NJDEP published new rules that establish a mechanism for New Jersey to re-enter the RGGI. This will 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 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 Connecticut Department of Energy and Environmental Protection 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 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. Note 14. 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. Note 13. Commitments and Contingent Liabilities. Adverse outcomes

Table of Contents

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.

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.

The Tax Act made significant changes to U.S. tax law. Among other things, 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 and interest disallowance rules. However, the Tax Act is unclear in certain respects and will require interpretations and the implementation of regulations by the Internal Revenue Service (IRS), as well as state taxing authorities. Further, 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 2018 the IRS issued a Notice of Proposed Rulemaking (Notice) regarding the application of tax depreciation rules and issued proposed regulations addressing the interest disallowance rules. However, certain aspects of the Notice and proposed regulations are unclear; therefore, we recorded taxes based on our interpretation of the relevant statutes.

These interpretations are subject to change based on several factors including, but not limited to, the IRS issuing final guidance and/or further clarification. We are subject to the provisions of the Financial Accounting Standards Board Accounting Standards Codification 740, Income Taxes, which require 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. Note 21. Income Taxes.

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 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 the 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:

- the impacts of economic downturns, including increased unemployment and less demand from C&I customers;
- regulatory incentives to reduce energy consumption;
- mandated energy efficiency measures;
- DSM tools;
- technological advances; and
- a shift in the composition of our customer base from C&I customers to residential customers.

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

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

A substantial portion of Power's generation output has been sold forward under fixed price power sales contracts and Power also sells forward the output from its intermediate and peaking facilities when it deems it commercially advantageous to do so.

Table of Contents

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 forgo 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 transmission infrastructure. We also cannot predict whether transmission facilities will invest 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. Investment in 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, obtain regulatory approval for, 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 T&D 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;

Table of Contents

- 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.

In January 2018, the governor of New Jersey signed Executive Order No. 8 directing the BPU to begin the process of moving the state toward its 2030 goal of 3,500 MW of offshore wind energy generation. An initial solicitation was established for 1,100 MW of offshore wind, with bids due in December. In connection with the bid submitted by Ocean Wind, LLC, a wholly owned subsidiary of Ørsted US Offshore Wind, referred to as the Ocean Wind project, PSEG agreed to provide energy management services and the potential lease of land for use in project development. We also retained an option to acquire an equity interest in the project. If the Ocean Wind bid is successful and PSEG elects to acquire an equity interest, PSEG would be required to incur additional capital expenditures. The amount of such capital expenditures, if any, cannot be determined at this time.

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 T&D business, the cost of storm restoration efforts may not be fully recoverable through the regulatory process. In addition, the inability to restore power to our customers on a timely basis could also materially damage our reputation.

Table of Contents

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

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

Any inability to recover the carrying amount of our 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 76%, 82% and 70% of the total assets of PSEG, PSE&G and Power, respectively, as of December 31, 2018. 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 Powerton coal generation investment; overall financial condition of lease counterparties; and the quality and condition of assets under lease.

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

36

Table of Contents

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 pre-tax 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 and T&D 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, 2018, approximately 73% 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 certain of 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 and T&D 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 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:

- disruption of the operation of our assets, the fuel supply chain 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

Table of Contents

breaches of vendors' infrastructures where our confidential information is stored.

We and our third-party vendors have been and likely will continue to be subject to attempted cybersecurity attacks. While there has been no material impact on our business or operations from these attempted attacks, 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, damage to our reputation 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 Item 1. Business—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, T&D 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.

Table of Contents

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. Note 14. Commitments and Contingent Liabilities.

Generation Facilities

Power

As of December 31, 2018, 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:					
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		4,253		1,607	
Nuclear:					
Hope Creek	NJ	1,173	100%	1,173	Nuclear
Salem 1 & 2	NJ	2,278	57%	1,308	Nuclear
Peach Bottom 2 & 3 (B)	PA	2,450	50%	1,225	Nuclear
Total Nuclear		5,901		3,706	
Combined Cycle:					
Keys (C)	MD	761	100%	761	Gas
Bergen	NJ	1,229	100%	1,229	Gas/Oil
Linden	NJ	1,300	100%	1,300	Gas/Oil
Sewaren 7 (D)	NJ	538	100%	538	Gas/Oil
Bethlehem	NY	815	100%	815	Gas
Kalaeloa	HI	208	50%	104	Oil
Total Combined Cycle		4,851		4,747	
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 (E)	NJ	420	50%	210	
Total Power Plants		16,613		11,458	

(A) Operated by GenOn Northeast Management Company.

(B) Operated by Exelon Generation.

(C) Commenced commercial operation in mid-2018.

(D) Commenced commercial operation in mid-2018, replacing our 100%-owned steam generation Sewaren Units 1 through 4 that had a 445 MW capacity.

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

As of December 31, 2018, Power also owned and operated 414 MW dc of PV solar generation facilities in various states.

Table of Contents

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, 2018, PSE&G’s electric T&D system included approximately 24,000 circuit miles, and 855,000 poles, of which 64% are jointly-owned. In addition, PSE&G owns and operates 52 switching stations with an aggregate installed capacity of 37,378 megavolt-amperes (MVA) and 244 substations with an aggregate installed capacity of 8,228 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, 2018, 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 and three liquid petroleum air gas 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, 2018, PSE&G had 122 MW dc of installed PV 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. Note 14. Commitments and Contingent Liabilities.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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. under the trading symbol “PEG.” As of February 15, 2019, there were 58,399 registered holders.

The following graph shows a comparison of the five-year cumulative return assuming \$100 invested on December 31, 2013 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.

	2013	2014	2015	2016	2017	2018
PSEG	\$100.00	\$134.36	\$130.62	\$153.85	\$187.34	\$196.09
S&P 500	\$100.00	\$113.68	\$115.24	\$129.02	\$157.17	\$150.27
DJ Utilities	\$100.00	\$130.65	\$126.65	\$149.67	\$169.65	\$173.01
S&P Electrics	\$100.00	\$128.98	\$122.73	\$142.72	\$160.00	\$166.57

Table of Contents

On February 19, 2019, our Board of Directors approved a \$0.47 per share common stock dividend for the first quarter of 2019. This reflects an indicative annual dividend rate of \$1.88 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.

In December 2018, 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 2019. There were no common share repurchases in the open market during the fourth quarter of 2018.

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2018:

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	231,933	\$ 33.49	12,992,138
Employee Stock Purchase Plan	—	—	2,888,361
Total	231,933	\$ 33.49	15,880,499

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Note 19. 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.

Table of Contents

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.

PSEG Years Ended December 31,	2018	2017	2016	2015	2014
	Millions, except Earnings per Share				
Operating Revenues (A)	\$9,696	\$9,094	\$8,966	\$10,415	\$10,886
Income from Continuing Operations (B)(C)(D)	\$1,438	\$1,574	\$887	\$1,679	\$1,518
Net Income (B)(C)(D)	\$1,438	\$1,574	\$887	\$1,679	\$1,518
Earnings per Share:					
Income from Continuing Operations					
Basic	\$2.85	\$3.12	\$1.76	\$3.32	\$3.00
Diluted	\$2.83	\$3.10	\$1.75	\$3.30	\$2.99
Net Income					
Basic	\$2.85	\$3.12	\$1.76	\$3.32	\$3.00
Diluted	\$2.83	\$3.10	\$1.75	\$3.30	\$2.99
Dividends Declared per Share	\$1.80	\$1.72	\$1.64	\$1.56	\$1.48
As of December 31,					
Total Assets	\$45,326	\$42,716	\$40,070	\$37,535	\$35,287
Long-Term Obligations (E)	\$13,168	\$12,071	\$10,897	\$8,837	\$8,218

(A) Amounts for 2017 and 2016 have been retrospectively adjusted to reflect new guidance for Revenue from Contracts with Customers adopted on January 1, 2018. Amounts for 2015 and 2014 were not required to be adjusted for this guidance and are therefore not comparative. For additional information, see Item 8. Note 2. Recent Accounting Standards.

(B) Income from Continuing Operations and Net Income for 2018 includes after-tax net unrealized losses on equity securities of approximately \$125 million in accordance with new accounting guidance effective January 1, 2018. Income from Continuing Operations and Net Income include an after-tax gain for 2018 of \$39 million from the sale of Power's Hudson and Mercer coal/gas generation plants and after-tax expenses for 2017 and 2016 of \$577 million and \$396 million, respectively, related to the early retirement of these plants; after-tax charges for 2018, (C) 2017 and 2016 totaling \$5 million, \$45 million and \$92 million, respectively, related to investments in REMA's leveraged leases; and an after-tax insurance recovery for 2015 of \$102 million for Superstorm Sandy. See Item 8. Note 4. Early Plant Retirements, Note 8. Long-Term Investments and Note 9. Financing Receivables for additional information.

(D) 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. Note 21. Income Taxes for additional information for 2017.

(E) Includes capital lease obligations.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

Table of Contents

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 regulated 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; 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 2018 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 2018 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand.

PSE&G

At PSE&G, our focus is on enhancing system reliability and resiliency, meeting customer expectations and supporting public policy objectives by investing capital in T&D infrastructure and clean energy projects. Over the past few years, our investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G. Over the next five years, we expect to invest between \$11 billion and \$16 billion in our business which is expected to provide an annual rate base growth of 7%—9%. We completed our Energy Strong Program I (ES I) and essentially completed our Gas System Modernization Program I (GSMP I). See Item 1. Business—Business Operations and Strategy—PSE&G for a description of these programs.

In May 2018, we received approval for our Gas System Modernization Program II (GSMP II), an expanded, five-year program to invest \$1.9 billion beginning in 2019 to replace approximately 875 miles of cast iron and unprotected steel mains in addition to other improvements to the gas system. Approximately \$1.6 billion will be recovered through periodic rate roll-ins, with the remaining \$300 million to be recovered through a future base rate proceeding. As part of the settlement, PSE&G agreed to file a base rate proceeding no later than five years from the commencement of the program, to maintain a base level of gas distribution capital expenditures of \$155 million per year and to achieve

certain leak reduction targets.

In June 2018, we filed for our Energy Strong Program II (ES II), a proposed five-year \$2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient. The size and duration of ES II, as well as certain other elements of the program, are subject to BPU approval. The review process is expected to conclude in mid-2019.

In October 2018, we filed our proposed Clean Energy Future (CEF) program with the BPU, a six-year estimated \$3.6 billion investment covering four programs; (i) an Energy Efficiency (EE) program totaling \$2.5 billion of investment designed to

Table of Contents

achieve energy efficiency targets required under New Jersey's Clean Energy law; (ii) an Electric Vehicle (EV) infrastructure program; (iii) an Energy Storage (ES) program and (iv) an Energy Cloud (EC) program which will include installing approximately two million electric smart meters and associated infrastructure. The review process for the CEF-EE program is expected to conclude by the third quarter of 2019. The CEF-EV/ ES and CEF-EC programs will have separate procedural schedules.

In November 2018, the New Jersey Division of Rate Counsel (Rate Counsel) filed a motion to dismiss the CEF-EC filing on the basis that the BPU announced a moratorium on electric distribution companies' AMI program. In December 2018, Rate Counsel filed a motion to stay the CEF-EV/ES filing, arguing that the BPU should conclude other regulatory proceedings addressing EVs and ES, including the new Energy Master Plan and initiatives required by the Clean Energy Act, before it rules on PSE&G's program. We opposed Rate Counsel's motions, asking for the BPU to permit these filings to proceed. There is no timetable for the BPU to decide on Rate Counsel's motions. Also, in October 2018, the BPU issued an Order approving the settlement of our distribution base rate proceeding with new rates effective November 1, 2018. The settlement resulted in a net reduction in overall annual revenues of approximately \$13 million, comprised of a \$212 million increase in base revenues, which includes the recovery of deferred storm costs, and the return of tax benefits largely due to tax reform of approximately \$225 million. The Order provides for a distribution rate base of \$9.5 billion, a 9.6% return on equity (ROE) for our distribution business and a 54% equity component of our capitalization structure.

Power

At Power, we strive to improve performance and reduce costs in order to optimize cash flow generation from our fleet in light of low wholesale power and gas prices, environmental considerations and competitive market forces that reward efficiency and reliability. Power continues to move its fleet toward improved efficiency and believes that its investment program enhances its competitive position with the addition of efficient, clean, reliable combined cycle gas turbine capacity. Our commitments for load, such as basic generation service (BGS) in New Jersey and other bilateral supply contracts, are backed by this generation or may be combined with the use of physical commodity purchases and financial instruments from the market to optimize the economic efficiency of serving our obligations. 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 Unit 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and enhance the environmental profile and overall efficiency of Power's generation fleet.

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 2018, our utility achieved continued strong reliability and customer satisfaction results, as well as comprehensive storm preparation and restoration efforts, and ongoing cost control, diverse fuel mix and dispatch flexibility allowed us to generate approximately 56 terawatt hours while addressing fuel availability and price volatility, and total nuclear fleet achieved a capacity factor of 91.4%.

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 2018 as we maintained sufficient liquidity, maintained solid investment grade credit ratings, and increased our indicative annual dividend for 2018 to \$1.80 per share.

We expect to be able to fund our planned capital requirements, as described in Liquidity and Capital Resources, and the impacts of the Tax Cuts and Jobs Act of 2017 (Tax Act) without the issuance of new equity. For additional information on the impacts of the Tax Act, see Item 8. Note 7. Regulatory Assets and Liabilities and Note 21. Income Taxes.

Table of Contents

The financial results for PSEG, PSE&G and Power for the years ended December 31, 2018 and 2017 are presented below:

	Years Ended December 31, 2018 2017	
	Millions, except per share data	
PSE&G	\$1,067	\$973
Power	365	479
Other	6	122
PSEG Net Income	\$1,438	\$1,574
PSEG Net Income Per Share (Diluted)	\$2.83	\$3.10

Our 2018 over 2017 decrease in Net Income was due primarily to the one-time favorable impacts in 2017 of new tax legislation at Power and Holdings, discussed below, and the recognition in 2018 of net unrealized losses on NDT Fund equity securities at Power in accordance with new accounting guidance. The decrease was partially offset by charges in 2017 related to the early retirement of our Hudson and Mercer units, as well as a lower federal tax rate at Power and higher earnings from T&D investments and the favorable impact of new rates upon settlement of the distribution base rate proceeding, discussed above, at PSE&G. For a more detailed discussion of our financial results, see Results of Operations.

Disciplined Investment

We utilize rigorous 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 2018, we

made additional investments in T&D infrastructure projects,

- continued to execute our GSMP I, Energy Efficiency and other existing BPU-approved utility programs,

received approval for our GSMP II program and filed our proposed ES II and CEF programs, and

commenced commercial operation of Sewaren 7 and Keys generation facilities and continued construction of our BH5 generation project, which is targeted for commercial operation in mid-2019.

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. For additional information about regulatory, legislative and other developments that may affect the company, see Item 1. Business—Regulatory Issues.

Transmission Planning

There are several matters pending before FERC that may impact the allocation of costs associated with transmission projects, including those 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 customers in New Jersey. In addition, as a 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 would 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 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.

In October 2018, FERC issued an order establishing a new framework for determining whether a company's ROE is unjust and unreasonable. FERC proposes to rely on financial models to establish a composite zone of reasonableness that will be used to determine whether an ROE complaint should be dismissed. If FERC determines that an ROE for a company is not just and reasonable, it intends to reset the ROE based on averaging the results of various financial models. We are still analyzing the potential impact of these methodologies and cannot predict the outcome of ongoing ROE proceedings.

45

Table of Contents

Wholesale Power Market Design

In June 2018, FERC issued an order finding that PJM's current capacity market is not just and reasonable because it enabled state-supported resources to bid below their costs which resulted in suppressed clearing prices. In particular, FERC found that nuclear generating units that receive zero emission certificate (ZEC) payments were of concern. Depending on the outcome of this matter, our generating stations could also be impacted. For additional information see Item 1. Business—Regulatory Issues—Federal Regulation.

In February 2019, the PJM Board approved a filing to modify the curves used for pricing reserves with FERC. The reforms include a 30-minute reserve product in real-time, more dynamic reserve requirements to better capture operator actions taken to maintain reliability, and improvement to the curves used to price reserves during reserve shortage conditions. If placed into effect, this reform is expected to improve energy and reserve prices by ensuring that when operators commit resources to ensure reliability, the commitments are reflected in market clearing prices. However, this reform could result in lower capacity payments. There is no timeline for this type of filing and therefore we cannot predict when FERC will act on the filing or the outcome of this matter.

In October 2018, PJM filed with FERC to revise the shape of the Variable Resource Requirement (VRR) curve that will be implemented for the capacity auction to be held in August 2019. The VRR curve is the administratively determined demand curve that serves as one of the key elements for establishing the amount of generation capacity to be procured in the auction. PJM contends that its proposal will lower capacity prices as compared to the currently effective VRR curve. PSEG protested PJM's proposal on the grounds that it would result in understated prices for capacity relative to the cost of constructing a new reference generating unit and will result in prices that are unjust and unreasonable. This matter is pending before FERC and we cannot predict the outcome.

Distribution

Effective in January 2018, the BPU adopted Infrastructure Investment Program (IIP) regulations that encourage 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 traditional utility infrastructure that enhances reliability, resiliency, and/or safety. Since these regulations were adopted, the BPU approved our GSMP II and we filed our ES II and CEF-EC programs with the BPU.

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 Clean Water Act requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In August 2018, the EPA released the proposed Affordable Clean Energy (ACE) rule as a replacement for the EPA's Clean Power Plan. The proposed ACE rule gives states great flexibility to evaluate specific heat rate improvement technologies and practices to be applied at coal-fired electric generating units. States have three years from the date of finalization to submit a plan that establishes a standard of performance that reflects the degree of emission limitation through the application of heat rate improvement technologies and practices. We cannot estimate the impact of this action on our business or results of operations at this time.

We are also 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.

In December 2018, the New Jersey Department of Environmental Protection proposed two rules that begin the state's re-entry into the Regional Greenhouse Gas Initiative (RGGI). The first proposal is the mechanism rulemaking that establishes the state's initial cap on greenhouse gas emissions of 18 million tons in 2020. The proposal follows the RGGI model rule with a cap that will decline three percent annually through 2030 to a final cap of 11.5 million tons. New Jersey is committed to a start date of January 1, 2020. The second proposal establishes the framework for how the state will spend the RGGI auction proceeds. We cannot estimate the impact of this action on our business or results of operations at this time.

Table of Contents

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. Note 14. Commitments and Contingent Liabilities.

Early Plant Retirements

Nuclear

In May 2018, the governor of New Jersey signed legislation, referred to as the ZEC legislation, that recognizes that nuclear power is a critical component of New Jersey's clean energy portfolio and an important element of a diverse energy generation portfolio that currently meets approximately 40 percent of New Jersey's electric power needs. The ZEC legislation creates a Zero Emission Certificate (ZEC) program to be administered by the BPU. The BPU subsequently established processes to evaluate applications by qualified nuclear plants and to review and approve changes to the New Jersey's electric distribution companies' tariffs to provide for the purchase of ZECs from selected nuclear plants and recover those ZEC payments through a non-bypassable distribution charge (ZEC charge) in the amount of \$0.004 per kilowatt-hour (which is equivalent to approximately \$10 per megawatt hour (MWh) in payments to selected nuclear plants. ZECs will be awarded to selected nuclear plants, if any, in April 2019 at which time ZEC revenue would commence and would continue for approximately three years. Nuclear plants receiving ZEC payments will be obligated to maintain operations, subject to exceptions specified in the ZEC legislation. The ZEC legislation requires nuclear plants to reapply for any subsequent three year periods. The ZEC payment may be adjusted by the BPU (a) at any time to offset environmental or fuel diversity payments that a selected nuclear plant may receive from another source or (b) at certain times specified in the ZEC legislation if the BPU determines that the purposes of the ZEC legislation can be achieved through a reduced charge that will nonetheless be sufficient to achieve the state's air quality and other environmental objectives by preventing the retirement of nuclear plants.

In December 2018, Power submitted applications to the BPU for the Salem 1 and 2 and Hope Creek nuclear plants. These were the only applications received by the BPU. As required, Power's three applications each included a certification pursuant to which Power confirmed that each of the Salem 1, Salem 2 and Hope Creek plants will cease operations within three years absent a material financial change. Power's submittal further attested that the nuclear plants are not expected to cover their costs and operating and market risks as defined in the ZEC legislation, absent a material financial change. As a result, absent a material financial change, Power will retire all three plants unless all of the plants receive ZECs. Power operates its nuclear plants as an interdependent fleet on a common site with shared costs and services, which allows them to achieve economies of scale. A decision to retire one nuclear plant would also adversely impact Power's ability to attract and retain qualified employees at its remaining plants. Power believes that the retirement of any individual nuclear plant would have the effect of decreasing the scale of its nuclear operations; however, the complex nature of operating nuclear plants would not decrease the attention required from management for the safe operation of the remaining nuclear operations. As a result, Power's decision to retire any nuclear plant would be made at the site level and would result in the retirement of all of these New Jersey nuclear plants.

Given the anticipated timing of the BPU's decision on which nuclear plants, if any, have been selected to receive ZECs, which is expected in April 2019, in March 2019 Power will submit to the PJM Independent Market Monitor and the PJM Office of Interconnection a request for a preliminary exception to PJM's Reliability Pricing Model must-offer requirement with respect to Power's interest for each of the Salem 1, Salem 2 and Hope Creek plants in connection with the 2022/2023 capacity auction expected to be held in August 2019. Power will also submit a deactivation notice to the extent that its filing deadline occurs prior to the award of ZECs by the BPU. If all of the Salem and Hope Creek plants are selected to receive ZECs, the preliminary exception and requested deactivation notice, as applicable, would be withdrawn.

In the event that any of the Salem 1, Salem 2 and Hope Creek plants is not selected to receive ZEC payments in April 2019 by the BPU and do not otherwise experience a material financial change, Power will take all necessary steps to retire all of these plants at or prior to their refueling outages scheduled for the Fall 2019 in the case of Hope Creek, Spring 2020 in the case of Salem 2 and Fall 2020 in the case of Salem 1. Alternatively, if all of the Salem 1, Salem 2 and Hope Creek plants are selected to receive ZEC payments in April 2019 but the financial condition of the plants is materially adversely impacted by potential changes to the capacity market construct being considered by FERC (absent sufficient capacity revenues provided under a program approved by the BPU in accordance with a FERC

authorized capacity mechanism), Power would still take all necessary steps to retire all of these plants. The costs and accounting charges associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, potential penalties associated with the early termination of capacity obligations and fuel contracts, accelerated asset retirement costs, severance costs, environmental remediation costs and, in certain circumstances, potential additional funding of the Nuclear Decommissioning Trust (NDT) Fund, would be material to both PSEG and Power.

Following any action to retire its nuclear plants, Power would take the necessary steps to satisfy its capacity obligations through 2022 with other assets in its fleet or through market purchases. Power intends to decommission any retired nuclear plant using the "SAFESTOR" process, which is a process approved by the NRC. As a result, Power believes adequate funds are available in the NDT Fund for the early retirement of the nuclear plants. To the extent another decommissioning process is employed, the NDT Fund would not be sufficient to cover the costs of decommissioning all the nuclear plants upon early retirement.

Table of Contents

Fossil

In December 2018, Power completed the sale of the sites of the retired Hudson and Mercer units. Power transferred all land rights and structures on the sites to a third-party purchaser, along with the assumption of the environmental liabilities for the sites. As a result of the sale and transfer of liabilities, Power recorded a pre-tax gain in 2018 of \$54 million in Operation and Maintenance (O&M) Expense.

In addition, PSEG and Power continue to monitor their other coal assets, including their interest in 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.

California Solar Facilities

As part of its solar production portfolio, Power owns and operates two California-based solar facilities with an aggregate capacity of approximately 30 MW direct current whose output is sold to Pacific Gas and Electric Company (PG&E) under power purchase agreements (PPAs) with twenty year terms. The net book value of these solar facilities was approximately \$57 million as of December 31, 2018. In January 2019, PG&E and its parent company PG&E Corporation filed for Chapter 11 bankruptcy protection. Power cannot predict the ultimate outcome that this bankruptcy proceeding will have on our ability to collect all of the future revenues from these facilities due under the PPAs; however, any adverse changes to the terms of Power's PPAs as a result of this bankruptcy proceeding could result in the future impairment of these assets in amounts up to their current net book value.

Offshore Wind

In January 2018, the governor of New Jersey signed Executive Order No. 8 directing the BPU to begin the process of moving the state toward its 2030 goal of 3,500 MW of offshore wind energy generation. An initial solicitation was established for 1,100 MW of offshore wind, with bids due in December 2018. In connection with the bid submitted by Ocean Wind, LLC, a wholly owned subsidiary of Ørsted US Offshore Wind, referred to as the Ocean Wind project, PSEG agreed to provide energy management services and the potential lease of land for use in project development. We also retained an option to acquire an equity interest in the project. We expect to make a decision regarding an equity investment in the Ocean Wind project in the second half of 2019.

Leveraged Leases

In December 2018, NRG REMA, LLC (REMA) emerged from its in-court proceeding under Chapter 11 of the Bankruptcy Code. Upon emergence, PSEG received \$31.5 million in cash in exchange for transferring the ownership interests in Keystone and Conemaugh to the debtholders of REMA and satisfaction of all other claims asserted against REMA, as well as certain amendments to the Shawville lease. The Shawville lease amendments, among other things, will allow REMA to express interest in a renewal on or after November 24, 2019. In addition, REMA has agreed to fund qualifying credit support up to \$36 million. As a result of the restructuring, Energy Holdings recognized a pre-tax gain in Operating Revenues of approximately \$12 million (\$9 million after tax). In addition, the remaining deferred tax liabilities related to these lease investments were reclassified to current tax liabilities. PSEG expects to pay approximately \$120 million to taxing authorities resulting from this restructuring activity.

Additional facilities in our leveraged lease portfolio include the Joliet and Powerton generating facilities. 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 Tax Act, 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 and interest disallowance rules.

As a result of the Tax Act, we recorded a one-time, non-cash earnings benefit of \$745 million in 2017, including \$588 million related to Power and \$147 million related to Energy Holdings. This benefit was primarily due to the remeasurement of deferred tax balances. In addition, PSE&G recorded excess deferred taxes of approximately \$2.1 billion and recorded an approximate \$2.9 billion revenue impact of these excess deferred taxes as Regulatory Liabilities.

Table of Contents

Beginning in 2018, PSEG, on a consolidated basis, is incurring lower income tax expense resulting in a decrease in its effective income tax rate that has led to an increase in 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. For PSE&G, the Tax Act has led to lower customer rates due to lower income tax expense recoveries and the BPU and FERC have approved our proposal to refund excess deferred income tax Regulatory Liabilities. See Item 8. Note 7. Regulatory Assets and Liabilities for additional information. The impact of the lower federal income tax rate on PSE&G was reflected in PSE&G's distribution base rate proceeding and its 2018 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.

In August 2018, the Internal Revenue Service (IRS) issued a Notice of Proposed Rulemaking (Notice) regarding the application of tax depreciation rules as amended by the Tax Act. While the Notice provides some guidance as to the application of the changes made by the Tax Act to the bonus depreciation rules, certain aspects remain unclear. Further, in November 2018 the IRS issued Proposed Regulations addressing the interest disallowance rules contained in the Tax Act. For non-regulated businesses, these rules set a cap on the amount of interest that can be deducted in a given year. Any amount that is disallowed can be carried forward indefinitely. For 2018, PSEG and Power expect that a portion of their interest will be disallowed in the current period but realized in future periods. However, certain aspects of the proposed regulations are unclear; therefore, we recorded taxes based on our interpretation of the relevant statute.

We recorded amounts based on our interpretation of the Tax Act, the depreciation rules contained in the Notice and proposed interest disallowance regulations. Such amounts are subject to change based on several factors, including but not limited to, the IRS and state taxing authorities issuing final guidance and/or further clarification. Any further guidance or clarification could impact PSEG's, PSE&G's and Power's financial statements. For additional information, see Item 8. Note 21. Income Taxes.

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 customers. We adjusted the revenue requirement in certain of our rate matters as a result of the change in the federal income tax rate. See Item 8. Note 7. Regulatory Assets and Liabilities for additional information.

In July 2018, the State of New Jersey made changes to its income tax laws, including imposing a temporary surtax on allocated corporate taxable income of 2.5% effective January 1, 2018 and 2019 and 1.5% in 2020 and 2021, as well as requiring corporate taxpayers to file in a combined reporting group as defined under New Jersey law starting in 2019. Both provisions include an exemption for public utilities. We believe PSE&G meets the definition of a public utility and, therefore, will not be impacted by the temporary surtax or be included in the combined reporting group. We expect these new provisions to unfavorably affect our non-utility business. In accordance with GAAP accounting for income taxes, deferred taxes are required to be measured at the enacted tax rate expected to apply to taxable income in the periods in which the deferred taxes are expected to settle. The newly enacted New Jersey tax legislation did not have a material impact on PSEG's deferred income tax balance.

Amendments to Other Postretirement Employee Benefit (OPEB) Plans

In December 2018, PSEG amended certain provisions of its OPEB plans applicable to all current and future Medicare-eligible retirees and spouses who receive or will receive subsidized healthcare from PSEG. Effective January 1, 2021, the PSEG-sponsored Medicare-eligible plans will be replaced by a Medicare private exchange. For each Medicare-eligible retiree and spouse, PSEG will provide annual credits to a Health Reimbursement Arrangement, which can be used to pay for medical, prescription drug, and dental plan premiums, as well as certain out-of-pocket costs. The amendment resulted in a \$559 million reduction in PSEG's OPEB obligation as of December 31, 2018 and is expected to decrease net periodic benefit costs in 2019.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in an environment with low gas prices, to capitalize on or otherwise address 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, reliability and customer satisfaction and complying with applicable standards and requirements,

• successfully manage our energy obligations and re-contract our open supply positions in response to changes in prices and demand,

• obtain approval of and execute our utility capital investment program, including ES II, GSMP II, our CEF program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,

• effectively manage construction of BH5 and our other generation projects,

49

Table of Contents

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.

In addition to the risks described elsewhere in this Form 10-K for 2019 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 proceedings,

the review by the BPU of our application to select our New Jersey nuclear generation units to receive payments under the ZEC program,

the continuing impacts of the Tax Act and changes in state tax laws, and

the impact of reductions in demand and lower natural gas and electricity prices and increasing environmental compliance costs.

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, customers 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, clean energy investments and/or generation projects, including offshore wind opportunities,

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, including the operation of T&D facilities outside of our traditional service territory, 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.

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

RESULTS OF OPERATIONS

	Years Ended		
	December 31,		
	2018	2017	2016
Earnings (Losses)	Millions		
PSE&G	\$1,067	\$973	\$889
Power (A)(B)	365	479	18
Other (B)(C)	6	122	(20)
PSEG Net Income	\$1,438	\$1,574	\$887
PSEG Net Income Per Share (Diluted)	\$2.83	\$3.10	\$1.75

Power's results in 2018 include an after-tax gain of \$39 million from the sale of its Hudson and Mercer coal/gas (A) generation plants and after-tax expenses of \$577 million and \$396 million in 2017 and 2016, respectively, related to

Table of Contents

the early retirement of these generation plants. See Item 8. Note 4. Early Plant Retirements for additional information.

Results in 2017 include the non-cash net income benefit of \$745 million, including \$588 million related to Power (B) 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.

Other includes after-tax activities at the parent company, PSEG LI and Energy Holdings as well as intercompany (C) eliminations. Energy Holdings recorded after-tax charges totaling \$5 million, \$45 million and \$92 million related to its investments in REMA's leveraged leases in 2018, 2017 and 2016, respectively. See Item 8. Note 8.

Long-Term Investments and Note 9. Financing Receivables for further information.

Power's results above include the NDT Fund activity and the impacts of non-trading commodity mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income attributable to changes related to the NDT Fund and MTM are shown in the following table:

Years Ended December 31,	2018	2017	2016
	Millions, after tax		
NDT Fund and Related Activity (A) (B)	\$(90)	\$62	\$—
Non-Trading MTM Gains (Losses) (C)	\$(84)	\$(99)	\$(100)

NDT Fund Income (Expense) includes gains and losses on NDT securities which are recorded in Net Gains (Losses) on Trust Investments. See Item 8. Note 10. Trust Investments for additional information. NDT Fund (A) Income (Expense) also includes interest and dividend income and other costs related to the NDT Fund recorded in Other Income (Deductions), interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) recorded in O&M Expense and the depreciation related to the ARO asset recorded in Depreciation and Amortization (D&A) Expense.

Net of tax (expense) benefit of \$54 million, \$(72) million and \$(5) million for the years ended December 31, 2018, (B) 2017 and 2016, respectively.

Net of tax benefit of \$33 million, \$68 million and \$68 million for the years ended December 31, 2018, 2017 and (C) 2016, respectively.

The 2018 year-over-year decrease in Net Income was driven largely by non-cash Net Income benefits in 2017 related to new tax legislation (See Item 8. Note 21. Income Taxes) at Power and Energy Holdings, and recognition in 2018 of net unrealized losses on equity securities in the NDT Fund in accordance with new accounting guidance effective January 1, 2018 (See Item 8. Note 2. Recent Accounting Standards and Note 10. Trust Investments),

These decreases were partially offset by accelerated depreciation in 2017 related to early retirement of our Hudson and Mercer coal/gas generation units at Power (See Item 8. Note 4. Early Plant Retirements),

the favorable impact at Power from the lower federal tax rate effective January 1, 2018, and higher earnings due to investments in T&D programs and the favorable impact of new rates effective November 1, 2018 as a result of the BPU approval of our distribution base rate proceeding.

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. Note 21. 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. Note 8. Long-Term Investments).

Table of Contents

These increases were partially offset by:

• higher charges related to the early retirement of our Hudson and Mercer coal/gas generation units at Power (See Item 8. Note 4. 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.

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. Note 25. Related-Party Transactions.

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2018	2017	2016	2018 vs. 2017	2017 vs. 2016		
	Millions			Million%		Million%	
Operating Revenues	\$9,696	\$9,094	\$8,966	\$602	7	\$128	1
Energy Costs	3,225	2,778	2,901	447	16	(123)	(4)
Operation and Maintenance	3,015	2,901	2,991	114	4	(90)	(3)
Depreciation and Amortization	1,158	1,986	1,476	(828)	(42)	510	35
Income from Equity Method Investments	15	14	11	1	7	3	27
Net Gains (Losses) on Trust Investments	(143)	134	(6)	(277)	N/A	140	N/A
Other Income (Deductions)	85	82	102	3	4	(20)	(20)
Non-Operating Pension and OPEB Credits (Costs)	76	—	(22)	76	N/A	22	N/A
Interest Expense	476	391	385	85	22	6	2
Income Tax (Benefit) Expense	417	(306)	411	723	N/A	(717)	N/A

The 2018, 2017 and 2016 amounts in the preceding table for Operating Revenues and O&M costs each include \$458 million, \$438 million and \$410 million, respectively, for PSEG LI's subsidiary, Long Island Electric Utility Servco, LLC (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. Note 5. 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.

Table of Contents

PSE&G

	Years Ended December			Increase /		Increase /	
	2018	2017	2016	(Decrease)		(Decrease)	
				2018 vs.	2017 vs.	2017 vs.	2016
	Millions			2017	2016	2016	
				Million	%	Million	%
Operating Revenues	\$6,471	\$6,324	\$6,303	\$147	2	\$21	—
Energy Costs	2,520	2,421	2,644	99	4	(223)	(8)
Operation and Maintenance	1,575	1,458	1,465	117	8	(7)	—
Depreciation and Amortization	770	685	565	85	12	120	21
Net Gains (Losses) on Trust Investments	(1)	2	—	(3)	N/A	2	N/A
Other Income (Deductions)	80	85	79	(5)	(6)	6	8
Non-Operating Pension and OPEB Credits (Costs)	59	(8)	(15)	67	N/A	7	(47)
Interest Expense	333	303	289	30	10	14	5
Income Tax Expense	344	563	515	(219)	(39)	48	9

Year Ended December 31, 2018 as compared to 2017

Operating Revenues increased \$147 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased \$44 million.

Transmission revenues increased \$180 million due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.

Gas distribution revenues increased \$67 million due to \$63 million from higher sales volumes, \$36 million from the inclusion of the GSMP I in base rates, \$25 million from an increase in the distribution tariff rates effective November 1, 2018 and \$2 million in higher collections of Green Program Recovery Charges (GPRC). These increases were partially offset by lower Weather Normalization Clause (WNC) revenues of \$31 million, a \$26 million reduction for Tax Adjustment Credits (TAC) and a \$2 million reduction in ES I collections.

Electric distribution revenues increased \$62 million due primarily to a \$49 million increase in sales volume, a \$17 million increase in ES I collections, \$6 million from an increase in the distribution tariff rates effective November 1, 2018 and \$4 million in higher collections of GPRC. These increases were partially offset by a reduction of \$14 million in TAC.

Transmission, electric distribution and gas distribution revenue requirements were \$265 million lower as a result of rate reductions due to the Tax Act which reduced the corporate income tax rate. This decrease is offset in Income Tax Expense.

Clause Revenues increased \$2 million due to higher Societal Benefit Charges (SBC) of \$14 million, and \$2 million in higher Solar Pilot Recovery Charge (SPRC) collections, partially offset by decreases of \$7 million in Margin Adjustment Clause (MAC) revenues and \$7 million in TAC and GPRC deferrals. The changes in SBC, SPRC and MAC collections and TAC and GPRC deferrals were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, D&A and Interest and Tax Expense. PSE&G does not earn margin on SBC, SPRC or MAC collections or on TAC or GPRC deferrals.

Commodity Revenues increased \$99 million due to higher Electric revenues and higher Gas revenues. This increase is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and basic gas supply service (BGSS) to retail customers.

Electric revenues increased \$73 million due to \$67 million in higher net BGS revenues reflecting \$148 million from higher BGS sales volumes partially offset by \$81 million from lower prices, and \$6 million in higher revenues from solar renewable energy credit (SREC) sales.

Gas revenues increased \$26 million due to \$65 million from higher BGSS sales volumes, which were partially offset by lower BGSS prices of \$42 million, and \$3 million in higher BGSS Asset Charges.

Table of Contents

Operating Expenses

Energy Costs increased \$99 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance increased \$117 million, due to a \$24 million increase in electric distribution maintenance expenditures, a \$24 million increase in transmission maintenance expenditures, a \$16 million increase in appliance service costs, a \$12 million net increase for various clause mechanisms and GPRC expenditures, a \$9 million increase in storm-related costs, an \$8 million increase in gas distribution expenditures, a \$6 million net increase in pension and OPEB expenses, net of amounts capitalized, a \$3 million increase in damage claims, and a \$15 million increase in other operating expenses.

Depreciation and Amortization increased \$85 million due primarily to an increase in depreciation of \$81 million due to additional plant placed into service, a \$7 million net increase in amortization of Regulatory Assets primarily due to the settlement of our base rate proceeding and an increase of \$5 million in software amortization, partially offset by a \$7 million increase in capitalized depreciation.

Non-Operating Pension and OPEB Credits (Costs) reflect an increase of \$67 million in credits primarily due to the adoption of new accounting guidance effective January 1, 2018 which no longer allows for the capitalization of any portion of these benefit costs. See Item 8. Note 2. Recent Accounting Standards.

Other Income (Deductions) decreased \$5 million due primarily to a \$2 million decrease in the Allowance for Funds Used During Construction (AFUDC) and a \$3 million decrease in solar loan interest.

Interest Expense increased \$30 million due primarily to increases of \$16 million due to long-term debt issuances in May and December 2017, \$8 million due to net long-term debt issuances in 2018 and \$4 million in clause-related interest.

Income Tax Expense decreased \$219 million due primarily to the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018 and lower pretax income.

Year Ended December 31, 2017 as compared to 2016

Operating Revenues increased \$21 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.

Gas distribution revenues increased \$30 million due to a \$16 million increase due to Energy Strong I, \$10 million from inclusion of the GSMP I 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 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 I revenues.

Clause Revenues increased \$75 million due to the absence of the return in 2016 to customers of overcollections of Securitization Transition Charge (STC) revenues of \$59 million, higher GPRC collections of \$28 million and higher MAC revenues of \$4 million. These increases were partially offset by lower SBC of \$17 million. The changes in STC, GPRC, 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, GPRC, MAC or SBC collections.

Commodity Revenues decreased \$223 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 \$288 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 (NUG) Charges due primarily to lower prices, a \$14 million decrease from sales of SRECs and \$14 million in lower revenues from the decreased sales volume of NUG energy.

Gas revenues increased \$65 million due to higher BGSS prices of \$68 million and \$2 million from higher sales volumes, partially offset by \$5 million in lower BGSS Asset Charges.

Operating Expenses

Energy Costs decreased \$223 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance decreased \$7 million due primarily to a \$15 million decrease in appliance service costs, partially offset by an \$8 million net increase in other operating expenses.

Table of Contents

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.

Non-Operating Pension and OPEB Credits (Costs) reflect a decrease in costs of \$7 million due primarily to a decrease in the amortization of the net unrecognized actuarial pension loss, partially offset by the impacts of capitalization.

Other Income (Deductions) increased \$6 million due primarily to an increase in AFUDC.

Interest Expense increased \$14 million due primarily to an \$11 million increase 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.

Power

	Years Ended December			Increase /		Increase /	
	31,			(Decrease)		(Decrease)	
	2018	2017	2016	2018 vs.		2017 vs.	
	Millions			2017		2016	
				Million%		Millions	
Operating Revenues	\$4,146	\$3,860	\$3,861	\$286	7	\$(1)	—
Energy Costs	2,197	1,913	1,824	284	15	89	5
Operation and Maintenance	999	1,046	1,139	(47)	(4)	(93)	(8)
Depreciation and Amortization	354	1,268	881	(914)	(72)	387	44
Income from Equity Method Investments	15	14	11	1	7	3	27
Net Gains (Losses) on Trust Investments	(140)	125	(6)	(265)	N/A	131	N/A
Other Income (Deductions)	21	20	23	1	5	(3)	(13)
Non-Operating Pension and OPEB Credits (Costs)	15	8	(4)	7	88	12	N/A
Interest Expense	76	50	84	26	52	(34)	(40)
Income Tax Expense (Benefit)	66	(729)	(61)	795	N/A	(668)	N/A

Year Ended December 31, 2018 as compared to 2017

Operating Revenues increased \$286 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased \$199 million due primarily to

a net increase of \$113 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM region coupled with the commencement of commercial operations for Keys and Sewaren 7 in mid-2018, partially offset by lower average realized prices and higher purchases for wholesale load contracts in the PJM region, a net increase of \$110 million due to lower MTM net losses in 2018 as compared to 2017. Of this amount, there was a \$153 million increase due to gains on positions reclassified to realized upon settlement, partially offset by a net decrease of \$43 million due to changes in forward prices,

a net increase of \$26 million in capacity revenues due primarily to increases in auction prices in the PJM region,

a net increase of \$24 million resulting from a prior year reduction to revenue for excess federal income tax previously collected by Power's subsidiary, PSEG New Haven LLC, from ratepayers due to the change in federal tax rates, and

a net increase of \$7 million due to higher sales related to new solar projects,

partially offset by a decrease of \$82 million in electricity sold under our BGS contracts due to lower prices and lower volumes.

Table of Contents

Gas Supply Revenues increased \$87 million due primarily to an increase of \$61 million in sales under the BGSS contract, of which \$53 million was due to increases in sales volumes as a result of periods of colder weather in the heating season, coupled with \$8 million due to higher average sales prices, and an increase of \$42 million related to sales to third parties, of which \$26 million was due to higher sales volumes and \$16 million to higher average sales prices, partially offset by a decrease of \$16 million due to net MTM losses in 2018 compared to net gains in 2017.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased \$284 million due to

Generation costs increased \$167 million due primarily to higher fuel costs of \$158 million reflecting utilization of higher volumes of gas and oil in the PJM region, primarily due to the commencement of commercial operations of Keys and Sewaren 7 fossil stations in mid-2018, coupled with higher prices of natural gas in the PJM and New York regions and higher coal costs in the PJM and New England (NE) regions, and an increase of \$40 million due to MTM losses in 2018 as compared to gains in 2017 due to changes in forward prices, partially offset by a net decrease of \$22 million primarily due to a decrease in the volume of energy purchased in the NE region to serve load obligations, and a net decrease of \$14 million due to charges primarily related to additional retirement costs incurred in 2017 associated with the early retirement of the Hudson and Mercer units.

Gas costs increased \$117 million due primarily to an increase of \$75 million related to sales under the BGSS contract due primarily to a \$51 million increase in volumes sold due to periods of colder weather during the heating season in 2018 as compared to 2017, and \$24 million of higher average gas costs, and an increase of \$38 million related to sales to third parties, of which \$25 million was due to an increase in volumes sold coupled with \$13 million due to higher average gas costs.

Operation and Maintenance decreased \$47 million due primarily to a \$67 million decrease at our fossil plants, due primarily to a pre-tax gain of \$54 million on the sale of the Hudson and Mercer units in 2018 and associated shutdown costs incurred in 2017, partially offset by higher planned outage costs in 2018 associated with our various other fossil plants, partially offset by a \$22 million net increase at our nuclear facilities primarily due to higher planned outage costs at our 100%-owned Hope Creek nuclear plant in 2018 as compared to our 57%-owned Salem Unit 1 nuclear plant in 2017, coupled with higher accretion directly related to an increase in the nuclear ARO in 2017.

Depreciation and Amortization decreased \$914 million due primarily to a \$964 million decrease primarily due to accelerated depreciation recorded in 2017 for the early retirement of the Hudson and Mercer units, partially offset by a \$23 million increase due to Keys and Sewaren 7 fossil stations being placed into service, an increase of \$12 million in depreciation due to the increase in the nuclear ARO in late 2017, and a \$7 million increase in 2018 due primarily to a higher nuclear asset base from increased capitalized asset retirement costs.

Net Gains (Losses) on Trust Investments decreased \$265 million due primarily to the inclusion in 2018 of \$209 million of net unrealized losses on equity investments in the NDT Fund in accordance with new accounting guidance, and a \$64 million decrease in net realized gains on NDT Fund investments,

Table of Contents

partially offset by a \$12 million decrease in other-than-temporary impairments of equity securities in the NDT Fund. Non-Operating Pension and OPEB Credits (Costs) reflect an increase in credits of \$7 million due primarily to an increase in the expected return on pension plan assets.

Interest Expense increased \$26 million due primarily to a \$15 million increase due to a June 2018 debt issuance and \$11 million in lower capitalized interest as a result of Keys and Sewaren 7 fossil stations being placed into service. Income Tax Expense increased \$795 million due primarily to a one-time benefit recorded in 2017 as a result of the remeasurement of deferred tax balances and higher pre-tax income in 2018. This increase was partially offset by the favorable impacts in 2018 of a decrease in the federal statutory income tax rate from 35% in 2017 to 21% and the remeasurement of the reserve for uncertain tax positions in connection with a 2015 claim to carry back tax-defined nuclear decommissioning costs and the 2011 and 2012 federal tax audit.

Year Ended December 31, 2017 as compared to 2016

Operating Revenues decreased \$1 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased \$112 million due primarily to

- a decrease of \$100 million in electricity sold under our BGS contracts due primarily to lower volumes coupled with lower prices,

- a decrease of \$41 million in energy sales in the PJM and NE regions due primarily to lower average realized 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 \$12 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.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power's obligation under its BGSS contract with PSE&G. Energy Costs increased \$89 million due to

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.

Table of Contents

Generation costs increased \$23 million due primarily to 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, a net increase of \$17 million primarily due to an increase in the volume of energy purchases in the NE region to serve load obligations, and a net increase of \$10 million primarily due to higher transmission charges resulting from higher rates, partially offset by 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.

Operation and Maintenance decreased \$93 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, and a \$35 million net decrease at our nuclear facilities primarily due to lower planned outage costs at our 57%-owned Salem nuclear plants in 2017 as compared to our 100%-owned Hope Creek nuclear plant and Salem Unit 1 nuclear plant in 2016, partially offset by a \$5 million increase 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.

Net Gains (Losses) on Trust Investments increased \$131 million due primarily to a \$113 million increase in net realized gains on NDT Fund investments and lower other-than-temporary impairments of equity securities of \$16 million in the NDT Fund.

Non-Operating Pension and OPEB Credits (Costs) reflect an increase in credits of \$12 million due primarily to a decrease in the amortization of the net unrecognized actuarial pension loss.

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.

Table of Contents

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. 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 \$1.1 billion of term loan credit agreements, of which \$350 million is scheduled to expire in June 2019 and \$700 million in November 2020. 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 Standard & Poor's (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, 2018, our operating cash flow decreased by \$347 million. For the year ended December 31, 2017, our operating cash flow decreased by \$53 million. The net changes were primarily due to net changes from our subsidiaries as discussed below and net tax payments at Energy Holdings in 2018 as compared to tax refunds in 2017.

PSE&G

PSE&G's operating cash flow increased \$15 million from \$1,838 million to \$1,853 million for the year ended December 31, 2018, as compared to 2017, due primarily to an increase of \$171 million relating to accounts receivable and unbilled revenues resulting from higher collections and lower prices and volumes in 2018 and higher earnings, offset by tax payments in 2018 as compared to tax refunds in 2017.

PSE&G's operating cash flow decreased \$58 million from \$1,896 million to \$1,838 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.

Power

Power's operating cash flow decreased \$242 million from \$1,326 million to \$1,084 million for the year ended December 31, 2018, as compared to 2017, due to an increase in margin deposit requirements of \$157 million, lower earnings, a decrease in fuels, materials and supplies of \$81 million and an increase of \$52 million in payments to counterparties, offset by tax refunds in 2018 as compared to tax payments in 2017, and a \$96 million increase from net collections of counterparty receivables.

Table of Contents

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.

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. 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, 2018 were as follows:

Company/Facility	As of December 31, 2018		
	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	\$1,500	\$759	\$ 741
PSE&G	600	288	312
Power	2,100	154	1,946
Total	\$4,200	\$1,201	\$ 2,999

As of December 31, 2018, 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 \$857 million and \$848 million as of December 31, 2018 and 2017, respectively.

For additional information, see Item 8. Note 15. Debt and Credit Facilities.

Long-Term Debt Financing

During the next twelve months, PSEG has a \$350 million floating rate term loan maturing in June 2019 and \$400 million of 1.60% Senior Notes maturing in November 2019. PSE&G has \$250 million of 1.80% Medium Term Notes maturing in June 2019 and \$250 million of 2.00% Medium Term Notes maturing in August 2019. Power has a letter of credit backing \$44 million of Pennsylvania Economic Development Financing Authority Variable Rate Demand Bonds which expires in November 2019.

For a discussion of our long-term debt transactions during 2018, see Item 8. Note 15. 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, 2018, PSE&G's Mortgage coverage ratio was 3.8 to 1 and the Mortgage would permit up to

approximately \$6.3 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

60

Table of Contents**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. Power's bank credit agreements and outstanding notes also contain limitations on the incurrence of subsidiary debt and liens and certain of Power's outstanding notes require Power to repurchase such notes upon certain change of control events.

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

Ratings Triggers

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

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

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

Common Stock Dividends

	Years Ended		
	December 31,		
Dividend Payments on Common Stock	2018	2017	2016
Per Share	\$1.80	\$1.72	\$1.64
in Millions	\$910	\$870	\$830

On February 19, 2019, our Board of Directors approved a \$0.47 per share common stock dividend for the first quarter of 2019. This reflects an indicative annual dividend rate of \$1.88 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. Note 23. 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

61

Table of Contents

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.

	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, 2018, we had Other Comprehensive Income of \$28 million on a consolidated basis. Other Comprehensive Income was due primarily to an increase of \$46 million related to pension and other postretirement benefits, partially offset by \$17 million of net unrealized losses related to Available-for-Sale Securities and \$1 million of unrealized losses on derivative contracts accounted for as hedges. See Item 8. Note 22. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

Table of Contents

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 AFUDC 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 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.

	2019	2020	2021
	Millions		
PSE&G:			
Transmission	\$1,350	\$ 1,145	\$875
Distribution	740	820	820
Gas System Modernization Program	420	455	435
Solar/Energy Efficiency	70	55	5
Total PSE&G	\$2,580	\$ 2,475	\$ 2,135
Power:			
Baseline	\$165	\$ 130	\$150
Growth Opportunities	225	20	15
Other	5	15	20
Total Power	\$395	\$ 165	\$185
Other	\$40	\$ 55	\$40
Total PSEG	\$3,015	\$ 2,695	\$ 2,360

PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its T&D 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, modernization and replacement of equipment that has reached the end of its useful life.
- 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 June 2018, we filed for our ES II, a proposed five-year \$2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient. The size and duration of ES II, as well as certain other elements of the program, are subject to BPU approval.

In October 2018, we filed our proposed CEF program with the BPU, a six-year estimated \$3.6 billion investment program focused on achieving New Jersey's energy efficiency targets, supporting electric vehicle infrastructure, deploying energy storage, and implementing an EC program which will include installing approximately two million electric smart meters and associated infrastructure. The size and duration of the CEF program, as well as certain other elements of the program, are subject to BPU approval.

ES II and the CEF program are not included in PSE&G's projected capital expenditures in the above table.

Table of Contents

In 2018, PSE&G made \$2,901 million of capital expenditures, primarily for T&D system reliability. This does not include expenditures for cost of removal, net of salvage, of \$160 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.
- **Growth Opportunities**—investments associated with new construction, including 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 2018, Power made \$815 million of capital expenditures, excluding \$181 million for nuclear fuel, primarily related to various projects at Fossil 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. Note 15. 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. Note 21. 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	\$2,450	\$750	\$1,000	\$700	\$—
PSE&G	9,258	500	693	825	7,240
Power	2,850	44	1,356	950	500
Interest on Recourse Debt					
PSEG	152	61	72	19	—
PSE&G	5,564	342	651	609	3,962
Power	830	134	224	148	324
Operating Leases					
PSE&G	118	15	21	16	66
Power	110	11	26	22	51
Services	178	14	29	30	105
Other	5	1	3	1	—
Energy-Related Purchase Commitments					
Power	2,742	774	918	586	464
Total Contractual Cash Obligations	\$24,257	\$2,646	\$4,993	\$3,906	\$12,712
Liability Payments for Uncertain Tax Positions					
PSEG	\$112	\$112	\$—	\$—	\$—
PSE&G	62	62	—	—	—
Power	34	34	—	—	—

Table of Contents**OFF-BALANCE SHEET ARRANGEMENTS**

PSEG and Power issue guarantees, primarily in conjunction with certain of Power's energy contracts. See Item 8. Note 14. 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. Note 8. Long-Term Investments and Note 9. 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 accounting principles generally accepted in the United States (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	2018	2017	2016
Discount Rate	4.41 %	3.73 %	4.29 %
Expected Rate of Return on Plan Assets	7.80 %	7.80 %	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 expense in 2019 of approximately \$49 million, or \$11 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 fourteen years.

Table of Contents

Effect if Different Assumptions Used: As part of the business planning process, we have modeled future costs assuming a 7.80% expected rate of return and a 4.41% discount rate for 2019 expense. Actual future pension expense/income and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.

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

Assumption	% Change	Impact on Pension		
		Benefit Obligation as of December 31, 2018	Increase in Pension Expense in 2019	Increase to Pension Expense, net of Amounts Capitalized in 2019
		Millions		
Discount Rate	(1)%	\$ 746	\$ 39	\$ 32
Expected Rate of Return on Plan Assets	(1)%	N/A	\$ 50	\$ 50

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. Note 1. Organization, Basis of Presentation and Significant Accounting Policies, Note 17. Financial Risk Management Activities and Note 18. Fair Value Measurements.

Long-Lived Assets

Management evaluates long-lived assets for impairment and reassesses the reasonableness of their related estimated useful lives whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate, counterparty credit worthiness, or market conditions, could potentially indicate an asset's or asset group's carrying amount may not be recoverable or an asset's probability of operating through its estimated remaining useful life changes.

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

Table of Contents

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.

In addition, long-lived assets are depreciated under the straight-line method based on estimated useful lives. An asset's operating useful life is generally based upon operational experience with similar asset types and other non-operational factors. In the ordinary course, management, together with an asset's co-owners in the case of certain of our jointly-owned assets, makes a number of decisions that impact the operation of our generation assets beyond the current year. These decisions may have a direct impact on the estimated remaining useful lives of our assets and will be influenced by the financial outlook of the assets, including future market conditions such as forward energy and capacity prices, operating and capital investment costs and any state or federal legislation and regulations, among other items.

The assumptions used by management incorporate inherent uncertainties that are at times difficult to predict and could result in impairment charges or accelerated depreciation in future periods if actual results materially differ from the estimated assumptions utilized in our forecasts.

Effect if Different Assumptions Used: The above cash flow tests, and fair value estimates and estimated remaining useful lives may be impacted by a change in the assumptions noted above and could significantly impact the outcome, triggering additional impairment tests, write-offs or accelerated depreciation. For additional information on the potential impacts on our future financial statements that may be caused by a change in useful lives of certain of our generating assets. See Item 8. Note 4. Early Plant Retirements and Note 6. Property, Plant and Equipment and Jointly-Owned Facilities.

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. Note 8. Long-Term Investments and Note 9. 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 O&M 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 \$80 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 O&M.

67

Table of Contents

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 2018. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which generally 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, 2018. 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,
- SAFESTOR alternative, which assumes the nuclear facility can be safely stored and subsequently decommissioned in a period within 60 years after operations,
- DECON alternative, which assumes decommissioning activities begin after operations, 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. Had the following assumptions been applied, our estimates of the approximate impacts on the Nuclear ARO as of December 31, 2018 are as follows:

- A decrease of 1% in the discount rate would result in a \$32 million increase in the Nuclear ARO.
- An increase of 1% in the inflation rate would result in a \$260 million increase in the Nuclear ARO.
- If we were not reimbursed by the federal government for spent fuel costs as prescribed under the Nuclear Waste Policy Act, the Nuclear ARO would increase by \$346 million.
- If we would elect or be required to decommission under a DECON alternative at Salem and Hope Creek, the Nuclear ARO would increase by \$635 million.

If Power were to increase its early shutdown probability to 100% and retire Hope Creek and Salem starting in the Fall of 2019, which is significantly earlier than the end of their current license periods, the Nuclear ARO would increase by \$314 million. For additional information, see Item 8. Note 4. Early Plant Retirements.

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

Table of Contents

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 Regulatory 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. Note 7. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

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.

Table of Contents

Years Ended December 31,	MTM VaR Millions	
	2018	2017
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	\$ 21	\$ 39
Average for the Period	\$ 14	\$ 10
High	\$ 46	\$ 39
Low	\$ 6	\$ 5
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	\$ 32	\$ 60
Average for the Period	\$ 22	\$ 15
High	\$ 72	\$ 60
Low	\$ 9	\$ 8

See Item 8. Note 17. 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, 2018, a hypothetical 10% increase in market interest rates would result in \$2 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and a \$426 million decrease in the fair value of debt, including an \$18 million decrease at PSEG, a \$354 million decrease at PSE&G and a \$54 million decrease at Power.

Debt and Equity Securities

We have \$5.6 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, 2018, the portfolio included \$900 million of equity securities and \$978 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, 2018, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately \$90 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 5.87 years and a yield of 3.28%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2018, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately \$57 million.

Credit Risk

See Item 8. Note 17. 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 \$186 million, net of deferred taxes of \$354 million, as of December 31, 2018. These leveraged leases are concentrated in the U.S. energy industry. See Item 8. Note 9. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially

Table of Contents

mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Credit enhancements include affiliate guarantees and partial collateralization of the lessee with non-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 amount and timing of any potential reduction in net tax benefits generated by Energy Holdings' portfolio of investments is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, 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.

Table of Contents

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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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, 2018, 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 27, 2019, 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 27, 2019

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

72

Table of Contents

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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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 27, 2019

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

73

Table of Contents

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, 2018 and 2017, 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, 2018, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, 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 27, 2019

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

74

Table of ContentsPUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS

Millions, except per share data

	Years Ended December		
	31, 2018	2017	2016
OPERATING REVENUES	\$9,696	\$9,094	\$8,966
OPERATING EXPENSES			
Energy Costs	3,225	2,778	2,901
Operation and Maintenance	3,015	2,901	2,991
Depreciation and Amortization	1,158	1,986	1,476
Total Operating Expenses	7,398	7,665	7,368
OPERATING INCOME	2,298	1,429	1,598
Income from Equity Method Investments	15	14	11
Net Gains (Losses) on Trust Investments	(143)	134	(6)
Other Income (Deductions)	85	82	102
Non-Operating Pension and OPEB Credits (Costs)	76	—	(22)
Interest Expense	(476)	(391)	(385)
INCOME BEFORE INCOME TAXES	1,855	1,268	1,298
Income Tax Benefit (Expense)	(417)	306	(411)
NET INCOME	\$1,438	\$1,574	\$887
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	504	505	505
DILUTED	507	507	508
NET INCOME PER SHARE:			
BASIC	\$2.85	\$3.12	\$1.76
DILUTED	\$2.83	\$3.10	\$1.75

See Notes to Consolidated Financial Statements.

Table of ContentsPUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Millions

	Years Ended December		
	31,		
	2018	2017	2016
NET INCOME	\$1,438	\$1,574	\$887
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of \$11, \$(37) and \$(41) for the years ended 2018, 2017 and 2016, respectively	(17)	44	42
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of \$1, \$1 and \$(1) for the years ended 2018, 2017 and 2016, respectively	(1)	(2)	2
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of \$(18), \$(4) and \$8 for the years ended 2018, 2017 and 2016, respectively	46	(8)	(12)
Other Comprehensive Income (Loss), net of tax	28	34	32
COMPREHENSIVE INCOME	\$1,466	\$1,608	\$919

See Notes to Consolidated Financial Statements.

Table of ContentsPUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS

Millions

	December 31,	
	2018	2017
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	\$177	\$313
Accounts Receivable, net of allowances of \$63 in 2018 and \$59 in 2017	1,435	1,348
Tax Receivable	242	127
Unbilled Revenues	240	296
Fuel	331	289
Materials and Supplies, net	571	577
Prepayments	94	118
Derivative Contracts	11	29
Regulatory Assets	389	211
Other	17	4
Total Current Assets	3,507	3,312
PROPERTY, PLANT AND EQUIPMENT	44,201	41,231
Less: Accumulated Depreciation and Amortization	(9,838)	(9,434)
Net Property, Plant and Equipment	34,363	31,797
NONCURRENT ASSETS		
Regulatory Assets	3,399	3,222
Long-Term Investments	896	932
Nuclear Decommissioning Trust (NDT) Fund	1,878	2,133
Long-Term Receivable of VIEs	624	686
Rabbi Trust Fund	224	231
Goodwill	16	16
Other Intangibles	143	114
Derivative Contracts	1	7
Other	275	266
Total Noncurrent Assets	7,456	7,607
TOTAL ASSETS	\$45,326	\$42,716

See Notes to Consolidated Financial Statements.

Table of ContentsPUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS

Millions

	December 31,	
	2018	2017
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	\$1,294	\$1,000
Commercial Paper and Loans	1,016	542
Accounts Payable	1,451	1,694
Derivative Contracts	11	16
Accrued Interest	110	103
Accrued Taxes	26	48
Clean Energy Program	143	128
Obligation to Return Cash Collateral	136	129
Regulatory Liabilities	311	47
Other	437	461
Total Current Liabilities	4,935	4,168
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,713	5,240
Regulatory Liabilities	3,221	2,948
Asset Retirement Obligations	1,063	1,024
Other Postretirement Benefit (OPEB) Costs	704	1,455
OPEB Costs of Servco	501	542
Accrued Pension Costs	791	537
Accrued Pension Costs of Servco	109	129
Environmental Costs	327	357
Derivative Contracts	4	5
Long-Term Accrued Taxes	181	175
Other	232	221
Total Noncurrent Liabilities	12,846	12,633
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 14)		
CAPITALIZATION		
LONG-TERM DEBT		
	13,168	12,068
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2018 and 2017— 534 shares	4,980	4,961
Treasury Stock, at cost, 2018—30 shares; 2017—29 shares	(808)	(763)
Retained Earnings	10,582	9,878
Accumulated Other Comprehensive Loss	(377)	(229)
Total Stockholders' Equity	14,377	13,847
Total Capitalization	27,545	25,915
TOTAL LIABILITIES AND CAPITALIZATION	\$45,326	\$42,716

See Notes to Consolidated Financial Statements.

Table of ContentsPUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS

Millions

	Years Ended December		
	31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	\$1,438	\$1,574	\$887
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,158	1,986	1,476
Amortization of Nuclear Fuel	187	199	203
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	97	103	109
Impairment Costs for Early Plant Retirements	—	—	102
Provision for Deferred Income Taxes (Other than Leases) and ITC	568	(167)	474
Non-Cash Employee Benefit Plan Costs	70	89	127
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(149)	(159)	(6)
Gain on Sale of Hudson and Mercer Units	(54)	—	—
Net (Gain) Loss on Lease Investments	5	48	92
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	116	188	183
Net Change in Regulatory Assets and Liabilities	(153)	(188)	(138)
Cost of Removal	(160)	(107)	(131)
Net (Gains) Losses and (Income) Expense from NDT Fund	98	(156)	(26)
Net Change in Certain Current Assets and Liabilities			
Tax Receivable	17	65	303
Accrued Taxes	(69)	16	3
Margin Deposit	(247)	(90)	(76)
Other Current Assets and Liabilities	70	(72)	(179)
Employee Benefit Plan Funding and Related Payments	(101)	(81)	(103)
Other	22	12	13
Net Cash Provided By (Used In) Operating Activities	2,913	3,260	3,313
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(3,912)	(4,190)	(4,199)
Purchase of Emissions Allowances and RECs	(146)	(117)	(99)
Proceeds from Sales of Trust Investments	1,501	2,319	824
Purchases of Trust Investments	(1,473)	(2,340)	(856)
Other	114	72	82
Net Cash Provided By (Used In) Investing Activities	(3,916)	(4,256)	(4,248)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	474	154	24
Issuance of Long-Term Debt	2,750	2,175	2,675
Redemption of Long-Term Debt	(1,350)	(500)	(824)
Cash Dividends Paid on Common Stock	(910)	(870)	(830)
Other	(77)	(74)	(79)
Net Cash Provided By (Used In) Financing Activities	887	885	966
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(116)	(111)	31
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	315	426	395
Cash, Cash Equivalents and Restricted Cash at End of Period	\$199	\$315	\$426

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Supplemental Disclosure of Cash Flow Information:

Income Taxes Paid (Received)	\$99	\$(8) \$(245)
Interest Paid, Net of Amounts Capitalized	\$454	\$377	\$365
Accrued Property, Plant and Equipment Expenditures	\$517	\$722	\$664

See Notes to Consolidated Financial Statements.

79

Table of ContentsPUBLIC 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, 2016	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)	—	—	—	—	—	—	—	—