PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-K
February 26, 2014
Table of Contents

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

FORM 10-K
(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2013,
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800

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
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange
Public Service Electric and Gas Company	First and Refunding Mortgage Bonds 9 1/4% Series CC, due 2021 6 3/4% Series VV, due 2016 8%, due 2037 5%, due 2037	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
PSEG Power LLC	Limited Liability Company Membership Interest
Public Service Electric and Gas Company	Medium-Term Notes

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

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

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

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

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes x No ¨

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

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2013 was $16,421,163,580 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 January 31, 2014 was 506,164,959.

As of January 31, 2014, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and 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 2014 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 10, 2014, as specified herein.

TABLE OF CONTENTS

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 13. Commitments and Contingent Liabilities, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC) including our subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and risks,
- any deterioration in our credit quality or the credit quality of our counterparties, including in our leveraged leases,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient coverage or recover proceeds of insurance with respect to such events,
- cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as competition for certain transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
-

changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies and changes in customer behaviors, including energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

Table of Contents

FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information relating to any individual company is filed by such company on its own behalf. Power and PSE&G are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, Power and PSE&G. Depending on the context of each section, references to “we,” “us,” and “our” relate to PSEG or to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 186.

WHERE TO FIND MORE INFORMATION

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

PART I

ITEM 1. BUSINESS

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

Power	PSE&G
A Delaware limited liability company formed in 1999 that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy sales, fuel supply and energy trading functions. Earns revenues from selling under contract or on the spot market a range of diverse products such as electricity, natural gas, capacity, emissions credits and a series of energy-related products used to optimize the operation of the energy grid.	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. Has also implemented demand response and energy efficiency programs and invested in solar generation within New Jersey.

Our other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's transmission and distribution system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and our operating subsidiaries with certain management, administrative and general services at cost.

Table of Contents

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

Power

Through Power, we seek to produce low-cost energy 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. We use our owned generation combined with commodity contracts and financial instruments to cover our commitments for Basic Generation Service (BGS) in New Jersey and other bilateral supply contract agreements.

Products and Services

As a merchant generator, our profit is derived from selling a range of products and services under contract to power marketers and to others, such as investor-owned and municipal utilities, and to aggregators who resell energy to retail consumers, or in the open market. These products and services include:

- 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).
- Capacity—a product distinct from energy, is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch when it is needed to meet system demand. Capacity is typically priced in dollars per megawatt (MW) for a given sale period.
- 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 imposed on market participants.
- Emissions Allowances and Congestion Credits—Emissions allowances (or credits) represent the right to emit a specific amount of certain pollutants. Allowance trading is used to control air pollution by providing economic incentives for achieving reductions in the emissions of pollutants. 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.

Power also sells wholesale natural gas, primarily through a full requirements Basic Gas Supply Service (BGSS) contract with PSE&G to meet the gas supply requirements of PSE&G's customers. This long-term arrangement was for an initial period which extended through March 31, 2012 and continues on a year-to-year basis unless terminated by either party with a one year notice.

Approximately 46% 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, propane and refinery gas. Based upon the availability of natural gas beyond PSE&G's daily needs, Power also sells gas to others.

In addition to its nuclear and fossil generation fleet, Power owns and operates 88 MW of photovoltaic (PV) solar generation facilities and has a 50% ownership interest in an 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 comprise the vast majority of Power’s operations and financial performance.

Table of Contents

How Power Operates

We own approximately 13,466 MW of generation capacity, of which 13,274 MW of nuclear and fossil generation capacity 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.

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

•Generation Capacity

Power has approved the expenditure of $419 million for an extended power uprate of the Peach Bottom nuclear units. The uprate is expected to result in an increase in Power’s share of nominal capacity of approximately 130 MW. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Total expenditures through December 31, 2013 were $154 million.

Power has also approved the expenditure of $191 million for the upgrading of its natural gas-fired combined cycle units located at Bergen and Linden in New Jersey and at the Bethlehem Energy Center (BEC) unit located in New York. When completed in 2018, these upgrades will add approximately 152 MW of capacity and improve the heat rates of these units. Total expenditures through December 31, 2013 were $13 million.

For additional information on each of our generation facilities, see Item 2. Properties.

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels: 44% gas, 28% nuclear, 18% coal, 9% oil and 1% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2013 was approximately 53,000 gigawatt hours (GWh). The generation mix by fuel type has changed slightly in recent years due to the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units than our coal units. The following table indicates the proportionate share of generating output by fuel type in 2013.

Table of Contents

Generation by Fuel Type (A)	Actual 2013	
Nuclear:		
New Jersey facilities	38%	
Pennsylvania facilities	17%	
Fossil:		
Coal:		
Pennsylvania facilities	11%	
Connecticut facilities	1%	
Coal and Natural Gas:		
New Jersey facilities	2%	
Oil and Natural Gas:		
New Jersey facilities	24%	
New York facilities	7%	
Connecticut facilities	—%	(B)
Total	100%	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii
(B) Less than one percent

• Generation Dispatch

Our generation units are typically 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. On a capacity basis, our portfolio of generation assets consists of 33% base load, 43% load following and 24% peaking. This diversity helps to reduce the risk associated with market demand cycles and allows us to participate in the market at each segment of the dispatch curve.

• Base Load Units run the most and typically operate whenever they are available. These units generally derive revenues from 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 2013, our base load capacity factors were as follows:

Unit	2013 Capacity Factor
Nuclear	
Salem Unit 1	87.0%
Salem Unit 2	99.5%
Hope Creek	85.6%
Peach Bottom Unit 2	98.4%
Peach Bottom Unit 3	85.3%
Coal	
Keystone	83.7%
Conemaugh	79.1%

No assurances can be given that these capacity factors will be achieved in the future.

• Load Following Units typically operate between 20% and 80% of the time. The operating costs are higher per unit of output due to the use of higher-cost fuels such as oil, natural gas and, in some cases, coal or lower overall unit efficiency. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.

Table of Contents

- Peaking Units run the least amount of time and utilize higher-priced fuels. These units typically operate less than 20% of the time. Costs per unit of output tend to be much 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.

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 will 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.

The following chart depicts the unconstrained merit order of dispatch of our units in PJM Interconnection L.L.C. (PJM), the ISO in the region where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that market price fluctuations have resulted in changes from historical norms, with lower gas prices allowing some gas-fired generation to displace some coal-fired generation in the load-following portion of the curve.

The size of each facility's circle in the above chart illustrates the relative MW generating capacity of that facility. For additional information on each of our generation facilities, see Item 2. Properties.

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

This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas will often translate into significant 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 and forward prices imply 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. In addition, the prices do not reflect locational differences resulting from congestion or other factors, such as the availability of natural gas from the Marcellus and other shale-gas regions, which can be considerable. While these prices provide some perspective on past and future prices, the forward prices are highly volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

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

Table of Contents

- enrichment of uranium hexafluoride, and
- fabrication of nuclear fuel assemblies.
- Coal Supply—Our Keystone, Conemaugh and Bridgeport stations operate on coal. Our Hudson and Mercer stations have the ability to operate on both coal and natural gas. We have coal contracts with numerous suppliers. Coal is delivered to our units through a combination of rail, truck, barge or ocean shipments.

In order to control emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources was not available for this facility, its long-term operations would be adversely impacted since additional material capital expenditures would be required to modify this station to enable it to operate using a broader mix of coal sources.

- 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 three interstate pipelines with which we have contracted. In addition, we have firm gas transportation contracts to serve our BEC station in New York.

We have 1.3 billion cubic feet-per-day of firm transportation capacity under contract to meet our obligations under the BGSS contract. This transportation capacity includes approximately 0.6 billion cubic feet-per-day of access to the northeast Pennsylvania Marcellus shale gas region. We supplement that supply with a total storage capacity of 76 billion cubic feet. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet.

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

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather and other factors. For additional information, see Item 7. Management's Discussion and Analysis (MD&A)—Overview of 2013 and Future Outlook and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Markets and Market Pricing

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

- PJM Regional Transmission Organization—PJM conducts the largest centrally dispatched energy market in North America. It serves over 61 million people, nearly 20% of the total United States population, and has a 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 20 million and a peak demand of 33,939 MW. Our BEC station operates in New York.
- New England—The ISO-New England (ISO-NE) is the market coordinator for the New England Power Pool and for administering its energy marketplace which covers Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 14 million and a peak demand of 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

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

Commodity prices, such as electricity, gas, coal, oil and emissions, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. These commodity prices have been, and continue to be, subject to significant market volatility. 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

7

Table of Contents

replacement power; thereby placing us at greater risk should our generating units fail to function effectively or otherwise become unavailable.

Over the past few years, a decline in wholesale natural gas prices has resulted in lower electric energy prices. One of the reasons for the decline in natural gas prices is greater supply from more recently developed sources, such as shale gas. 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 capacity 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 constraints which raise concerns about reliability and create a more acute need for capacity.

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

The prices to be received by generating units in PJM for capacity have been set through RPM base residual 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 constraints in each area of the transmission system. Keystone and Conemaugh receive lower prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in northern New Jersey usually receive higher pricing.

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

Delivery Year	MW-day
June 2013 to May 2014	$244
June 2014 to May 2015	$162
June 2015 to May 2016	$167
June 2016 to May 2017	$166

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas.

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.

We have obtained price certainty for our PJM and New England capacity through May 2017 through the RPM and FCM pricing mechanisms.

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

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

Table of Contents

Hedging Strategy

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

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. In addition, the BGS-Fixed Price 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 New Jersey Board of Public Utilities (BPU). The volume of BGS contracts and the 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)	2010-2013	2011-2014	2012-2015	2013-2016	2014-2017
PSE&G	$95.77	$94.30	$83.88	$92.18	$97.39
Jersey Central Power & Light	$95.17	$92.56	$81.76	$83.70	$84.44
Atlantic City Electric	$98.56	$100.95	$85.10	$87.27	$87.80
Rockland Electric Company	$103.32	$106.84	$92.51	$92.58	$95.61

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in our hedges. Our 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. Our 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 electric distribution company (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 choose a third party supplier, as well as by other factors such as weather and the economy.

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

As of February 11, 2014, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2016.

Base Load Generation	2014	2015	2016
Generation Sales	100%	75%-80%	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 if little or no hedging activity had 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 2015 and a portion of 2016. We also have various long-term fuel purchase commitments for coal to support our fossil generation stations. These purchase obligations are consistent with our strategy to enter into contracts for its fuel supply in comparable volumes to our sales contracts.

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

Table of Contents

PSE&G

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

Products and Services

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

- Transmission—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the 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 BPU.

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

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

In addition to our current utility products and services, we have implemented several programs to increase the level of regulated solar generation within New Jersey, including:

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

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information

Table of Contents

concerning these programs and the components of our tariffs, see Regulatory Issues—State Regulation and Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

How PSE&G Operates

We are a transmission owner in PJM and we provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately three hundred 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 which considers Operations and Maintenance expenditures, Rate Base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Our approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information, see Regulatory Issues—Federal Regulation—Transmission Regulation.

Transmission Statistics

December 31, 2013		
Network Circuit Miles	Billing Peak (MW)	Historical Annual Load Growth 2009-2013
1,499	10,414	(0.5)%

During 2013, we continued to execute our five major regional transmission projects for which we were assigned construction responsibility by PJM:

Major Transmission Projects
As of December 31, 2013

Project	Total Estimated Project Costs Millions	Total Project Spend	Expected In-Service Date
Susquehanna-Roseland	$790	$661	June 2014/June 2015
Northeast Grid Reliability	$907	$228	June 2015
North Central Reliability	$390	$349	June 2014
Burlington-Camden 230kV	$399	$301	June 2014
Mickleton-Gloucester-Camden 230kV	$435	$122	June 2015

In December 2013, we were assigned construction by PJM of a new transmission project that will provide a double-circuit 345kV line in the Bergen-Linden Corridor to maintain reliability. This project has an expected in-service date of June 2018, and an estimated construction cost of up to $1.2 billion. The net increase in PSE&G's capital expenditures is expected to be less than the estimated cost of the 345 kV project, as it will eliminate the need for certain other projects that had been previously assigned by PJM.

Distribution

PSE&G distributes gas and electricity to end users in our service territory. Our load requirements were split among residential, commercial and industrial customers, as described in the following table for 2013. We believe that we have all the franchise rights (including consents) necessary for our electric and gas distribution operations in the territory we serve.

Table of Contents

	% of 2013 Sales	
Customer Type	Electric	Gas
Commercial	57%	36%
Residential	33%	60%
Industrial	10%	4%
Total	100%	100%

While our customer base has remained steady, gas load has increased and electric load has declined as illustrated:

Electric and Gas Distribution Statistics

	December 31, 2013 Number of Customers		Electric Sales and Gas Sold and Transported		Historical Annual Load Growth 2009-2013
Electric	2.2	Million	41,277	GWh	(1.1)%
Gas	1.8	Million	3,813	Million Therms	2.1%

The decline in electric sales is the result of changes in customer usage patterns, including conservation, and the slowdown in economic activity that occurred during the recent recession. Gas sales increased as a result of increased usage by non-firm customers as a result of lower gas prices and more favorable winter weather.

Solar Generation

In order to support New Jersey's Energy Master Plan and the state's renewable energy goals, we have undertaken two major solar initiatives at PSE&G, the Solar Loan Program and the Solar 4 All Program. 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 used to repay the loans through a periodic auction, the proceeds of which are used to offset program costs. Our Solar 4 All Program invests in utility-owned solar PV centralized solar systems installed on PSE&G property and third party sites, 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. As of December 31, 2013, we have invested an aggregate of approximately $700 million in both solar programs.

Supply

Although commodity revenues make up almost 43% of our revenues, we make no margin on the supply of electricity and gas since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to the BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type, which represents about 80% of PSE&G’s load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Fixed Price). 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-CIEP).

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

PSE&G procures the supply requirements of its default service BGSS gas customers through a full requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each

Table of Contents

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. See Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities for information on recent self-implementing credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not have third party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A—Overview of 2013 and Future Outlook.

Other

Energy Holdings primarily owns and manages a portfolio of lease investments. Over the past several years, we have terminated all of our international leveraged leases in order to reduce the cash tax exposure related to these leases. We have also reduced our risk by opportunistically monetizing all of our previous international investments.

The majority of Energy Holdings' remaining $825 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2013, 70% of our total leveraged lease investments were rated as below investment grade by Standard & Poor's.

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, Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables and Note 13. Commitments and Contingent Liabilities.

On December 31, 2013, PSEG Long Island LLC (PSEG LI) and the Long Island Power Authority (LIPA) entered into a twelve year Amended and Restated Operations Services Agreement (OSA) effective January 1, 2014 to operate LIPA’s electric transmission and distribution (T&D) system in Long Island, New York. As required by the OSA, PSEG LI also provides administrative support functions to LIPA. PSEG LI uses its brand in the Long Island T&D service area. Pursuant to the OSA, PSEG LI acts as LIPA's agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee, and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. In addition, there is the opportunity for the parties to extend the contract for an additional eight years subject to the achievement by PSEG LI of certain performance levels during the initial term of the OSA. Also, beginning in 2015, Power will provide fuel procurement and power management services to LIPA under separate agreements.

Table of Contents

COMPETITIVE ENVIRONMENT

Power

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

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

New additions of lower-cost or more efficient generation capacity could make our plants less economical 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 could 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 congestion 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 permitted to build transmission and who will pay the costs of future transmission could also impact our revenues.

Adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, would have the effect of artificially depressing prices in the competitive wholesale market and thus have the potential to harm competitive markets, on both a short-term and a long-term basis.

Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant, thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states. If any new legislation were to require our competitors to meet the environmental standards currently imposed upon us, we would likely have an economic advantage since we have already installed significant pollution-control technology at most of our fossil stations.

In addition, pressures from renewable resources could increase over time. For example, many parts of the country, including the mid-western region within the footprint of the Midwest Independent System Operator (MISO), the California ISO and the PJM region, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of “public policy” transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulation, below.

PSE&G

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

Changes in the current policies for building new transmission lines, such as those ordered by the FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that provide 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

Table of Contents

opportunities to build in other service territories. For additional information, see the discussion in Regulatory Issues—Federal Regulation—Transmission Regulation, below.

Construction of new local generation also has the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.

EMPLOYEE RELATIONS

As of December 31, 2013, we had 9,887 employees within our subsidiaries, including 6,125 covered under collective bargaining agreements. In December 2013, we reached agreement with one of our six labor unions to extend its collective bargaining agreement for three years through April, 2017. Our other collective bargaining agreements expire in April 2017 with three labor unions, in October 2017 with one labor union and in May 2018 with one labor union. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2013			
	Power	PSE&G	Other
Non-Union	1,224	1,548	990
Union	1,409	4,707	9
Total Employees	2,633	6,255	999

Effective January 1, 2014, in connection with our new management contract with LIPA we assumed the collective bargaining agreement between National Grid, LIPA's previous management contractor, and a labor union. This union contract expires in February, 2015. We commenced operations in Long Island with approximately 1,400 union employees and 700 non-union employees.

REGULATORY ISSUES

Federal Regulation

FERC

The FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. The 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 the 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.

The 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 the FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

The FERC also regulates Regional Transmission Operators/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
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

Table of Contents

Regulation of Wholesale Sales—Generation/Market Issues

Market Power

Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. They can sell power at cost-based rates or apply to the FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR authority, the FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power and/or that market power has been sufficiently mitigated and report in the interim to the FERC any material change in facts from those the FERC relied on in granting MBR authority.

PSE&G, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG New Haven LLC all have been granted MBR authority from the FERC. Each of these companies, except PSEG New Haven LLC (which received MBR authority in May 2012), filed a market power update with the FERC at the end of 2013, which the FERC must accept in order for these companies to retain MBR authority. Retention of MBR authority is important to the maintenance of our current generation business' revenues. The matter is pending.

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. The FERC rules also govern the overall design of these markets. At present, all units receive a single 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). These FERC rules have a direct impact on the energy prices received by our units.

Capacity Market Issues

PJM, the NYISO, and the ISO-NE each have capacity markets that have been approved by the FERC. The FERC regulates these markets and held a technical conference in September 2013 to examine whether the market design for these three capacity markets is working optimally. One of the specific issues being considered by the FERC is whether capacity market rules are properly responding to, and fostering the development of, state public policies, demand response and emerging technologies. We cannot predict what action, if any, the FERC might take with regard to capacity market design.

PJM—RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under 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 RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active. There is currently significant discussion about (i) the future role of demand response in the RPM market, including examining how demand response resources should be paid and how these resources and programs - both existing and planned - should be measured, verified and bid in RPM to ensure their availability, (ii) the setting of the Cost of New Entry (CONE) value for the RPM demand curve for the next three years, which is a major input in establishing the price generators will be paid in RPM, (iii) the future process for submitting below Minimum Offer Price Rule (MOPR) bids by subsidized generation into the capacity market, as further discussed below and (iv) the impact of “seams” issues on the PJM capacity market, such as the extent to which the rules governing generation located within PJM are being equally applied to generation imported into PJM from the MISO, as further discussed below.

The FERC has recently issued an order capping the amount of "limited" demand response resources (i.e. resources which can only be called on by PJM a limited number of times during the summer months) that can clear in PJM's capacity auctions. PJM expects that capping "limited" demand response participation will have an upward effect on capacity prices in the next auction.

MISO—MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. In the May 2013 RPM auction, the difference between the MISO and PJM capacity markets was highlighted, as significant amounts of MISO generation were bid as imports into PJM and cleared in RPM. MISO is seeking to facilitate additional exports. The FERC is currently examining this "capacity portability" issue. To the extent that MISO generation is not subject to the same types of rules and requirements as generation located within PJM, Power could be adversely impacted.

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. The FERC has recently issued an order requiring the implementation of a downward sloping demand curve, similar to the design in place in PJM, for use in ISO-NE's ninth capacity market auction to be held in February 2015 and effective in the 2018-2019 power year. This action is expected to result in greater stability of capacity prices in New

Table of Contents

England. As in PJM, capacity market rules in the ISO-NE continue to develop, with significant issues still under consideration, including the number and location of capacity zones to be utilized and how the ISO-NE addresses the impact of state-funded programs such as renewable resources.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. The NYISO capacity model currently recognizes only two separate zones that potentially may separate in price: New York City and Long Island. On August 13, 2013, the FERC issued an order approving NYISO's April 30, 2013 filing establishing the boundaries of a third capacity zone that will encompass the super zone that includes the lower Hudson Valley and New York City to take effect May 1, 2014. The FERC is also currently considering what type of generation unit should be used as the reference unit for the purposes of establishing the CONE in the "rest of State" zone (excluding the lower Hudson Valley, New York City and Long Island). This issue is significant since it will set the demand curve on which future capacity prices paid to generators will be based for the period May 1, 2014 through April 30, 2017. In January 2014, the FERC issued an order accepting the NYISO's proposed reference unit (a unit with no environmental controls), which may have the effect of depressing capacity prices. This order is subject to rehearing.

Discussions at the FERC concerning other potential changes to NYISO capacity markets, including rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons, are also ongoing.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)—In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs. The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into three SOCAs as directed by the State, but did so under protest reserving their rights.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. This federal court decision is currently being challenged on appeal in the Third Circuit Court of Appeals. The State of Maryland also took action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland. The federal court decision is currently being challenged in the Fourth Circuit Court of Appeals.

As a result of the New Jersey U.S. District Court's final decision, PSE&G terminated the SOCA contracts in November 2013 with CPV Shore, LLC (CPV), a subsidiary of Competitive Power Ventures, Inc. and Hess Newark, LLC (Hess), a subsidiary of Hess Corporation, the counterparties to two of the SOCA contracts, by providing written notice in accordance with the terms of the SOCA contracts. The third SOCA contract had been terminated earlier in 2013 due to a default by the generator.

Transmission Regulation

The 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 then trued up the following year to reflect actual annual expenses and capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments. For information about our transmission formula rate, including our 2014 Annual Formula Rate update filing with the FERC, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Our 2013 Annual Formula Rate Update with the FERC provided for approximately $174 million in increased annual transmission revenues effective January 1, 2013. Our 2014 Annual Formula Rate Update with the FERC provides for approximately $171 million in increased annual transmission revenues effective January 1, 2014.

- Transmission Policy Developments—The FERC concluded in Order No. 1000 that the incumbent transmission owner should not always have a "right of first refusal" (ROFR) to construct and own transmission projects in its service territory. We have challenged the FERC's elimination of the ROFR in federal court, which challenge remains pending. PJM is currently implementing new rules under which the construction of certain types of transmission projects is no longer subject to a ROFR for incumbents. The FERC has also approved the “state agreement approach” to cost allocation under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

Table of Contents

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

- Transmission Rate Proceedings—In September 2011, a complaint was filed by several state utility commissions and consumer advocates against transmission owners in New England challenging their base ROE. In August 2013, a FERC Administrative Law Judge (ALJ) issued a decision finding the utilities' base ROE to no longer be just and reasonable. In February 2013, several state utility commissions and consumer advocates, including the BPU and the New Jersey Division of Rate Counsel, also filed a complaint at the FERC challenging the base ROE and formula transmission rate implementation protocols of transmission owners in Maryland, Pennsylvania, Delaware and New Jersey. This complaint remains pending. In addition, on November 12, 2013, a group of industrial customers in MISO filed a complaint against the MISO transmission owners, requesting that the FERC reduce the transmission owners' base ROE and eliminate the ROE adders for among other things, participation in an RTO. Alternatively, the customers requested that the FERC find the base ROE to be unjust and unreasonable and expeditiously establish settlement procedures. Further, on February 6, 2014, a public power association in New York filed a complaint against one of the New York transmission owners asking the FERC to reduce the ROE used to calculate the transmission owner's rates. The results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

The FERC has issued an order setting for hearing and settlement procedures certain rate challenges raised by a municipal electric cooperative against a transmission owner in PJM. Specifically, the electric cooperative challenged the prudency of categories of costs included by the transmission owner in its formula rate. The FERC found that the challenges raised issues of fact that warranted examination at hearing. While we are not the subject of the challenge, the result of this proceeding could set a precedent for other transmission owners with formula rates in place, including PSE&G.

Compliance

- FERC Audit—Each of the PSEG companies that have MBR authority from the FERC is being audited by the FERC for compliance with its rules for (i) receiving and retaining MBR authority (ii) the filing of electric quarterly reports and (iii) our units' receipt of payments from the RTO/ISO when they are required to run for reliability reasons when it is not economical for them to do so. The FERC will issue a report at the conclusion of the audit.
- Reliability Standards—Congress has required the FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the United States electric transmission and generation system and to prevent major system blackouts. Many reliability standards have been developed and approved. These standards apply both to reliability of physical assets interconnected to the bulk power system and to the protection of critical cyber assets. In 2013, the FERC enacted new rules that will bring our generating units within the scope of the standards applicable to critical cyber assets and increase our compliance responsibilities.

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 record keeping and data reporting requirements applicable to commercial end users. The CFTC has also proposed rules establishing position limits for trading in certain commodities, such as natural gas, and we are currently analyzing the potential impact of these rules on our business.

18

Table of Contents

Nuclear Regulatory Commission (NRC)

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

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

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

In 2011, the NRC task force submitted a report containing various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. The NRC staff also issued a document which provided for a prioritization of the task force recommendations. The NRC approved the staff's prioritization and implementation recommendations subject to a number of conditions. Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1), to review filtration of boiling water reactor (BWR) primary containment vents and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and strive to implement the requirements by 2016. The NRC issued letters and orders to licensees implementing the Tier 1 recommendations in March 2012.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric BWRs utilizing the Mark I containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. Fukushima Daiichi Units 1-4 are BWRs equipped with Mark I containments. The petition names 23 of the total 104 active commercial nuclear reactors in the United States. While we do not believe the petition will be successful, we are unable to predict the outcome of any action that the NRC may take in connection with the petition.

On March 19, 2013, the NRC initiated a rulemaking process for improvements to venting systems at 31 U.S. BWRs with “Mark I” and “Mark II” containments (similar to those at Fukushima), which include our Hope Creek Unit and Peach Bottom Units 2 and 3. On June 6, 2013, the NRC issued orders requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vents with containment venting systems designed and installed to remain functional during severe accident conditions. For our Hope Creek and Peach Bottom units, final installation of the required modifications is expected to occur during the planned refueling outages in 2016-2018.

The NRC is currently developing the regulatory basis for the filtering strategies rulemaking. That evaluation is expected to be completed in December 2014. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident.

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

State Regulation

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

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the

Table of Contents

BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate case was settled in 2010. In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Item 8. Financial Statements and Supplementary Data—Note 6. Regulatory Assets and Liabilities.

Significant state regulatory matters that may have an impact on our business are as follows:

Energy Strong Program—In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our BPU jurisdictional electric and gas system to improve resiliency for the future. The changes that were described would be made over a ten-year period. In this petition, we are seeking approval to invest \$0.9 billion in our gas distribution system and \$1.7 billion in our electric distribution system over an initial five-year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. The current estimated cost of the entire program, including the first five years of investments for which we sought approval in this petition, is \$3.9 billion. We anticipate seeking BPU approval to complete our investment under the program at a later date. We have continued to respond to data requests from the BPU, the New Jersey Division of Rate Counsel and intervenors. All required public hearings were completed in October 2013, and the review of PSE&G’s proposal is ongoing at the BPU. We cannot predict the outcome of this matter. For additional information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements.

Storm Proceedings—In the fourth quarter of 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. In December 2012, the BPU issued an order allowing PSE&G to defer on its books actually incurred, prudent, incremental storm restoration costs associated with extraordinary storms, including Superstorm Sandy and Hurricane Irene, and not otherwise recoverable through base rates or insurance. In March 2013, the BPU initiated two generic proceedings with the New Jersey utilities, including PSE&G. The first was a proceeding to evaluate the prudency of storm costs incurred in 2011 and 2012 and the second was to evaluate major storm event mitigation proposals. In June 2013, PSE&G made its compliance filing in the storm cost prudency proceeding, providing certain details of our storm restoration costs for Superstorm Sandy as well as other major storms, including outage information, capital expenditures, operation and maintenance (O&M) expenses and incremental O&M expenses. We requested that the BPU issue an Order approving the compliance filing and specifically finding that the storm costs incurred were reasonable and prudent, and should be recovered from ratepayers. The review of the prudency of these expenses is now pending before the BPU. We cannot predict the outcome of this review. As of December 31, 2013, we had deferred \$245 million in storm costs as a Regulatory Asset.

New Jersey Energy Master Plan (EMP)—New Jersey law requires that an EMP be developed every three years, the purpose of which is to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment. While not having the force of law, the EMP provides an overview of energy policy in New Jersey and may provide both opportunities and challenges for PSEG. The most recent EMP was finalized in December 2011 and placed an emphasis on expanding in-state electricity resources, reducing energy costs, recognizing the impact of climate change and setting new targets for a renewable portfolio standard and goals for energy supplies from clean energy sources.

ENVIRONMENTAL MATTERS

Changing environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to reduce the health and environmental impacts of our operations. To the extent that environmental requirements are more stringent and compliance more costly in certain states where we operate compared to other states that are part of the same market, such rules may impact our ability to compete within that market. 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.

Areas of environmental regulation may include, but are not limited to:

- air pollution control,
- climate change,

Table of Contents

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

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

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes record keeping, 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.

- Nitrogen Oxide (NO_x) Regulation: New Jersey High Electric Demand Day—In April 2009, the New Jersey Department of Environmental Protection (NJDEP) finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel-fired electric generation units. The rule has an impact on our generation fleet, as it imposes NO_x emissions limits that require capital investment for controls or the retirement of up to 86 combustion turbines (approximately 1,750 MW) and four older New Jersey steam electric generation units (approximately 400 MW) by May 2015. See Item 8. Financial and Supplementary Data—Note 13. Commitments and Contingent Liabilities for further discussion of this issue.
- Hazardous Air Pollutants Regulation—In February 2012, the EPA published under the National Emission Standard for Hazardous Air Pollutants provisions of the CAA, Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources. The impact to our fossil generation fleet in New Jersey and Connecticut and our jointly-owned coal-fired generating facilities in Pennsylvania is further discussed in Item 8. Financial and Supplementary Data—Note 13. Commitments and Contingent Liabilities.
- Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation—In March and April 2013, we filed petitions at the EPA and in federal court, respectively, challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued on January 30, 2013. Among other things, the final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In our appeal, we are seeking more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. On June 28, 2013, the EPA announced that it would reconsider certain other items included in the final rule that are also subject to the appeal. We cannot predict the final outcome of the EPA's action regarding NESHAP.
- Cross-State Air Pollution Rule (CSAPR)—In July 2011, the EPA issued the final CSAPR, which limits power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS). In August 2012, the U.S. Court of Appeals for the D.C. Circuit (D.C. Court) vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. The purpose of CAIR is to improve ozone and fine particulate air quality within states that have not demonstrated achievement of the NAAQS. CAIR was implemented through a cap-and-trade program and, to date, the impact has not been material to us as the allowances allocated to our stations were sufficient. If 2014 operations are similar to those in the past four years, it is expected that the impact to our operations from CAIR in New Jersey, New York and Connecticut in 2014 will not be significant.

In June 2013, the Supreme Court announced that it would review the D.C. Court's decision. Oral arguments were held in December 2013. If the Supreme Court were to overturn the D.C. Court's ruling and reinstate CSAPR, we do not anticipate that there will be any material adverse impact on our earnings and financial condition. The EPA has announced its plan to propose a new rule in late 2014 to replace the vacated CSAPR that will solely address ozone NAAQS for NO_x. We cannot determine the impact that this new rule might have on us.

Table of Contents

Climate Change

- CO_2 Regulation Under the CAA—In April 2013, several industrial groups petitioned the Supreme Court to review various EPA rules issued under the CAA, including the Tailoring Rule, to regulate greenhouse gas (GHG) emissions, including CO_2. The Tailoring Rule requires a new source or an existing source which undergoes a major modification, to evaluate and perhaps install best available control technology (BACT) for GHG emissions. On October 15, 2013, the Supreme Court agreed to add the case to the docket for its current term to consider whether the EPA has authority to regulate CO_2 emissions of stationary sources, including power plants.

In April 2012, the EPA published the proposed New Source Performance Standards (NSPS) for GHG for new power plants only. On June 25, 2013, the President directed the EPA to propose revised NSPS for new power plants by September 20, 2013, propose GHG regulations for existing power plants by June 1, 2014, finalize such regulations by June 1, 2015 and require states to submit GHG implementation regulations by June 30, 2016.

On January 8, 2014, the EPA proposed revised NSPS for new power plants. The revised NSPS establish three emission standards for CO_2 emissions for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units, (ii) large natural gas combustion turbines, and (iii) small natural gas combustion turbines. The EPA is requesting comment on use of an electric output sales threshold to determine applicability to the NSPS. This electric output sales threshold would eliminate the outright exclusion of simple cycle combustion turbines which was proposed in the initial April 2012 NSPS. We cannot predict the final outcome of these proposed standards.

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

- Climate-Related Legislation—The federal government may consider legislative proposals to define a national energy policy and address climate change. Proposals under consideration include, but are not limited to, provisions to establish a national clean energy portfolio standard and to establish an energy efficiency resource standard. Provisions of any new proposal may present material risks and opportunities to our businesses. The final design of any legislation will determine the impact on us, which we are not now able to reasonably estimate.
- Regional Greenhouse Gas Initiative (RGGI)—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions.

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

On February 7, 2013, the RGGI States released an updated Model Rule that, among other things, reduces the amount of available regional CO_2 allowances beginning in 2014. Each RGGI State must implement the changes through state-specific regulations. We do not expect these changes, or any future changes, to the RGGI rules will have a material impact on us.

New Jersey withdrew from RGGI beginning in 2012. As a result, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances. This action has been challenged by environmental groups in the New Jersey state court. We cannot predict the outcome of this matter.

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

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program

Table of Contents

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 April 2013, the EPA issued notice of a proposed rule that would further limit the discharge of pollutants in wastewater from the operation of coal-fired generating facilities. Our co-owned Keystone and Conemaugh facilities continue to use technologies that generate these wastewater discharges. However, our other coal-fired facilities no longer discharge many of these types of wastewater pollutants. We are unable to predict the impact on Keystone and Conemaugh but do not believe there would be any material impact on our other coal-fired facilities.

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

- Cooling Water Intake Structure Regulation—In 2011, the EPA published a new proposed rule which did not establish any particular technology as the BTA (e.g. closed-cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. We reviewed the proposed rule, assessed the potential impact on our generating facilities and used this information to develop our comments to the EPA which were filed in August 2011. In June 2012, the EPA posted a Notice of Data Availability (NODA) requesting comment on a series of technical issues related to the impingement mortality proposed standards. The EPA also posted a second NODA outlining its plans to finalize a “Willingness to Pay” survey it initiated to develop non-use benefits data in support of the initial rule proposal. We and industry trade associations submitted comments on both NODAs in July 2012. The EPA has rescheduled the date for adoption of a final rule several times. The EPA is currently scheduled to issue a final rule on April 17, 2014.

If the rule were to be adopted as originally proposed, the impact on us would be material since the majority of our electric generating stations would be affected. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for additional information.

On October 1, 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court of New Jersey seeking to force the NJDEP to take action on our pending application for permit renewal at Salem either by denying the application or issuing a draft for public comment. The permit is currently pending the EPA’s finalization of the Clean Water Act 316(b) regulations. We were not named in the lawsuit nor do we know how this legal action will proceed but it could have a material impact on us.

Hazardous Substance Liability

The production and delivery of electricity, the distribution of gas and, formerly, the manufacture of gas, results 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. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

-

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

- Natural Resource Damages—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP

Table of Contents

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

Fuel and Waste Disposal

- Nuclear Fuel Disposal—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the U.S. Department of Energy (DOE) conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In June 2012, the court ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee.

Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. 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. In November 2013, the court ordered the DOE Secretary to submit a proposal to Congress to adjust the fee to zero. In January 2014, the DOE Secretary comported with the court order and submitted the zero fee adjustment change letter to Congress, subject to DOE appeal rights. Absent Congressional and/or further Court action, the fee will revert to zero after ninety days of continuous legislative session. The earliest this is anticipated to occur is in the third quarter of 2014. If the fee were to be eliminated, Power would see an annualized pre-tax benefit of approximately $30 million.

- 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.

- Coal Combustion Residuals (CCRs)—In June 2010, the EPA published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste. The final outcome of the EPA's proposed rulemaking cannot be predicted.

In April 2012, several environmental organizations and CCR marketers brought a citizens' suit against the EPA in federal court arguing that the EPA has a non-discretionary duty to issue the CCR rules by a certain date. In May 2012, the Utility Solid Waste Activities Group, of which PSEG is a member, filed a Motion to Intervene in order to be in alignment with the EPA in defending against the environmental organizations' action. On October 29, 2013, the Court issued a decision requiring the EPA to establish a regulatory deadline to issue the CCR Final Rule.

SEGMENT INFORMATION

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

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 financial position, results of operations or net cash flows and could cause results to differ materially from those expressed elsewhere in this report.

The factors discussed in Item 7. MD&A may also have a material adverse effect on our results of operations and cash flows and affect the market prices for our publicly-traded securities. While we believe that we have identified and discussed the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant.

We are subject to comprehensive and evolving regulation by federal, state and local regulatory agencies that affects, or may affect, our businesses.

We are subject to regulation by federal, state and local authorities. Changes in regulation can cause significant delays in or materially affect business planning and transactions and can materially increase our costs. Regulation affects almost every aspect of our businesses, such as our ability to:

- Obtain fair and timely rate relief—PSE&G's retail rates are regulated by the BPU and its wholesale transmission rates are regulated by the FERC. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of and on the authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU. Our utility's transmission rates are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. Transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates in New England and New York. These agencies and groups have filed complaints at the FERC asking the FERC 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.
- Obtain required regulatory approvals—The majority of our businesses operate under MBR authority granted by the FERC, which has determined that our subsidiaries do not have unmitigated market power and that MBR rules have been satisfied. Failure to maintain MBR eligibility, 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 us.

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

- Comply with regulatory requirements—There are federal standards, including mandatory NERC and Critical Infrastructure Protection standards, in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by the NERC for compliance.

Further, the FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, reporting, interlocking directorate rules and cross-subsidization. Our companies with MBR authority are currently being audited by the FERC for compliance with FERC's rules regarding MBR authority, the filing of Electric Quarterly Reports (EQRs) and the receipt of payments in organized markets by our generating units that are required to run for reliability reasons when it is not economical for them to do so.

We are subject to the reporting and record-keeping requirements of the Dodd-Frank Act, as implemented by the CFTC, and may in the future be subject to CFTC requirements regarding position limits for trading of certain commodities. As part of the Dodd-Frank Act compliance, we will need to be vigilant in monitoring and reporting our swap transactions.

The BPU 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. The BPU is near completion of a combined management audit and affiliate transactions audit of PSE&G.

Table of Contents

We are exposed to commodity price volatility as a result of our participation in the wholesale energy markets.
The material risks associated with the wholesale energy markets known or currently anticipated that could adversely affect our operations include:

- Price fluctuations and collateral requirements—We expect to meet our supply obligations through a combination of generation and energy purchases. We also enter into derivative and other positions related to our generation assets and supply obligations. As a result, we are subject to the risk of price fluctuations that could affect our future results and impact our liquidity needs. These include:
- variability in costs, such as changes in the expected price of energy and capacity that we sell into the market,
- increases in the price of energy purchased to meet supply obligations or the amount of excess energy sold into the market,
- the cost of fuel to generate electricity, and
- the cost of emission credits and congestion credits that we use to transmit electricity.

In the markets where we operate, natural gas prices typically have a major impact on the price that generators receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas usually translate into significant changes in the wholesale price of electricity.
Over the past few years, wholesale prices for natural gas have declined from the peak levels experienced in 2008. One reason for this decline is increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly. Over that time, generation by our coal units was also adversely affected by the relatively lower price of natural gas as compared to coal, making it sometimes more economical to run certain of our gas units than our coal units.
Natural gas prices may remain at low levels for an extended period and continue to decline if further advances in technology result in greater volumes of shale gas production.
Many factors may affect capacity pricing in PJM, including but not limited to:

- changes in load and demand,
- changes in the available amounts of demand response resources,
- changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.),
- increases in transmission capability between zones, and
- changes to the pricing mechanism, including increasing the potential number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time, including issues currently pending at the FERC.

Potential changes to the rules governing energy markets in which the output of our plants is sold also poses risk to our business, as discussed further below.
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. If Power were to lose its investment grade credit rating, 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. If Power had lost its investment grade credit rating as of December 31, 2013, it may have had to provide approximately $691 million in additional collateral. We may also be subject to additional collateral requirements which could be required under new rules being developed by the CFTC which are expected to be implemented in 2014.

- Our cost of coal and nuclear fuel may substantially increase—Our coal and nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire coal and nuclear fuel in the future. Market prices for coal and nuclear fuel have recently been volatile. Although our fuel contract portfolio provides a degree of hedging against these market risks, future increases in our fuel costs cannot be predicted with certainty and could materially and adversely affect liquidity, financial condition and results of operations. While our generation runs on diverse fuels, allowing for flexibility, the mix of fuels ultimately used can impact earnings.

Table of Contents

- Third party credit risk—We sell generation output and buy fuel through the execution of bilateral contracts. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could 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 whatever default mechanisms exist in those markets, some of which attempt to spread the risk across all participants, which may not be an effective way of lessening the severity of the risk of the amounts at stake. The impact of economic conditions may also increase such risk.

We are subject to numerous federal and state 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 environmental regulation by federal, state and local authorities regarding air quality, water quality, site remediation, land use, waste disposal, aesthetics, impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. Future changes may result in significant increases in compliance costs.

Delay in obtaining, or failure to obtain and maintain, any environmental permits or approvals, or delay in or failure to satisfy any applicable environmental regulatory requirements, could:

- prevent construction of new facilities,
- prevent continued operation of existing facilities,
- prevent the sale of energy from these facilities, or
- result in significant additional costs, each of which could materially affect our business, results of operations and cash flows.

In obtaining required approvals and maintaining compliance with laws and regulations, we focus on several key environmental issues, including:

- Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG 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. Legislation enacted in the states where our generation facilities are located establishes aggressive goals for the reduction of CO_2 emissions over a 40-year period. Multiple states are developing or have developed state-specific or regional initiatives to obtain CO_2 emissions reductions in the electric power industry. The RGGI is such a program in the Northeast. There could be significant costs incurred to continue operation of our fossil generation facilities, including the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities.
- CO_2 Litigation—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—Our Salem nuclear generating facility has a permit from the NJDEP allowing for its continued operation with its existing cooling water system. That permit expired in July 2006. Our application to renew the permit, filed in February 2006, estimated the costs associated with cooling towers for Salem to be approximately $1 billion, of which our share was approximately $575 million. The renewal filing has not been updated since the 2006 filing.

If the NJDEP and the Connecticut Department of Environmental Protection were to require installation of closed-cycle cooling or its equivalent at our Salem, Mercer, Hudson, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and net cash flows and would require further economic review to determine whether to continue operations or decommission the stations.

The EPA issued a proposed rule in 2011 regarding regulation of cooling water intake structures. If adopted as proposed, the impact of this rulemaking could significantly impact states' permitting decisions on whether to require closed cycle cooling and could materially increase our cost of compliance. The EPA is expected to issue a final rule in 2014.

Table of Contents

- Remediation of environmental contamination at current or formerly-owned facilities—We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. Also, we are 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, 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 flow. 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.
- More stringent air pollution control requirements in New Jersey—Most of our generating facilities are located in New Jersey where restrictions are generally considered to be more stringent in comparison to other states. Therefore, there may be instances where the facilities located in New Jersey are subject to more restrictive and, therefore, more costly pollution control requirements and liability for damage to natural resources, than competing facilities in other states. Most of New Jersey has been classified as "nonattainment" with NAAQS for one or more air pollutants. This requires New Jersey to develop programs to reduce air emissions. Such programs can impose additional costs on us by requiring that we offset any emissions increases from new electric generators we may want to build and by setting more stringent emission limits on our facilities that run during the hottest days of the year.
- Coal Ash Management—Coal ash is a CCR produced as a byproduct of generation at our coal-fired facilities. We currently have a program to beneficially reuse coal ash as presently allowed by federal and state regulations. In 2010, the EPA formally published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act. One of these options regulates CCRs as a hazardous waste. The outcome of the EPA rulemaking cannot be predicted. Proposed regulations which more stringently regulate coal ash, including regulating coal ash as hazardous waste, could materially increase costs at our coal-fired generation facilities. The EPA has not established a date for release of a final rule.

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

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

- Storage and Disposal of Spent Nuclear Fuel—We currently use on-site storage for spent nuclear fuel. Disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel, could impact future operations of these stations. In addition, the availability of an off-site repository for spent nuclear fuel may affect our ability to fully decommission our nuclear units in the future.
- Regulatory and Legal Risk—The NRC may modify, suspend or revoke licenses, or shut down a nuclear facility and impose substantial civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities. As with all of our generation facilities, as discussed above, our nuclear facilities are also subject to comprehensive, evolving environmental regulation. Our nuclear generating facilities are currently operating under NRC licenses that expire in 2033 through 2046.
- 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. Since our nuclear fleet provides the majority of our generation output, any significant outage could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.
- Nuclear Incident or Accident Risk—Accidents and other unforeseen problems have occurred at nuclear stations, both in the United States 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, operating results and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to

Table of Contents

operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages.

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 is located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's locational capacity market design rules and New England forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In January 2011, New Jersey enacted a law establishing a LCAPP which provided for the construction of subsidized base load or mid-merit electric power generation. The LCAPP legislation was invalidated on constitutional grounds by a federal court order issued in October 2013. However, future state actions to subsidize the construction of new generation could have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis.

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

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's capacity and energy revenues could be adversely affected. Moreover, the FERC has issued a rule, currently being challenged in court, that requires changes to transmission planning processes which may result in more transmission being built to facilitate renewable generation.

In this rule, the FERC has also acted to eliminate the ROFR, which will have the effect of allowing third parties to build certain types of transmission projects in the service territories of incumbent utilities such as PSE&G. As a result, we could face competitive pressures for our transmission business in New Jersey, as well as in in other utilities' service territories where we will be able to seek opportunities to build.

We face significant competition in the merchant energy 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 annual objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Some of our competitors include:

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

Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy markets, potentially resulting in erosion of our market share and impairment in the value of our power plants.

Changes in customer usage patterns and technology could adversely impact us.

- DSM and other efficiency efforts—DSM and other efficiency efforts aimed at changing the quantity and patterns of consumers' usage could result in a reduction in load requirements.

- Changes in technology and/or customer behaviors—It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, including distributed generation, such as fuel cells, micro turbines, micro grids, windmills and net-metered PV (solar) cells, 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. Substantial micro grid penetration can impact energy costs, system performance, and demand growth. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology and usage, such as municipal aggregation, could also alter the channels through which retail electric customers buy electricity, which could adversely affect our financial results. Increased reliance by customers on on-site generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities.

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

The revenues generated 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, 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.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur significant 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 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 and could require maintaining liquidity resources that would be prohibitively expensive.

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

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset’s or 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.

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

Capital for projects and investments has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and will need continued access to debt capital from outside sources in order to efficiently fund the construction and other cash flow needs of our businesses. The ability to arrange financing and the costs of capital depend on numerous factors including, among other things, general economic and market conditions, the availability of credit from banks and other financial institutions, investor confidence, the success of current projects and the quality of new projects.

The ability to have continued access to the credit and capital markets at a reasonable economic cost is dependent upon our current and future capital structure, financial performance, our credit ratings and the availability of capital under reasonable terms and conditions. As a result, no assurance can be given that we will be successful in obtaining re-financing for maturing debt or financing for projects and investments.

Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Sustained decreases in asset value of trust assets 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 pension and postretirement benefit plans and to decommission our nuclear generating plants. A decline in the market value of our pension assets could result in the need for us to make significant contributions in the future to maintain our funding at sufficient levels.

An extended economic recession 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 of commodities. Adverse conditions in the economy affect the markets in which we operate and can negatively impact our results. Declines in demand for energy will reduce overall sales and cash flows, especially as customers reduce their consumption of electricity and gas. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold and/or increases in non-payment of customer bills would materially adversely affect our liquidity, financial condition and results of operations.

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.

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 also exposed to the risk of accidents, severe weather events such as we experienced from Hurricane Irene and Superstorm Sandy, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. The physical risks of climate change, such as more frequent or more extreme weather events, changes in sea level, temperature and precipitation patterns and other related phenomena have 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 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.

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 market instability and volatility in fuel prices which could materially adversely affect our operations. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities, could be direct or indirect targets or be affected by terrorist or other criminal activity. Such events could severely disrupt business operations and prevent us from servicing our customers. In addition, new or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

Cybersecurity attacks or intrusions could adversely impact our businesses.

We own and/or operate generating stations, transmission and distribution facilities, which are dependent on the operation of our computing systems. Our ability to market our generation output and acquire and hedge fuel and power are also dependent on our computing systems. Our computing systems may be impacted by cybersecurity attacks, hostile technological intrusions, or inadvertent disclosure of company and/or customer information. Cybersecurity threats to our operations include:

- Disruption of the operation of our assets and the power grid,
- Information theft of confidential company, employee, shareholder, vendor or customer information, and
- 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.

If a significant cybersecurity event or breach should occur, it could result in material costs for repair and remediation, breach notification, operations, insurance and increased capital costs. Such a cyber incident could also cause us to be non-compliant with applicable laws, regulations or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings, regulatory fines and increased scrutiny, and possible damage to our reputation and brand. We devote resources to network and application security, encryption and other measures to protect our computing systems and infrastructure from unauthorized access or misuse and interface with numerous external entities to improve our cybersecurity situational awareness. However, given the ever changing nature of cybersecurity threats, there can be no assurance the steps we take can protect us against all possible occurrences.

Table of Contents

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

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

Our success will depend, in part, on our ability to obtain necessary regulatory approvals, complete these projects within budgets, on commercially reasonable terms and conditions and, in our regulated businesses, our ability to 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.

We may be unable to achieve, or continue to sustain, our expected levels of operating performance.

One of the key elements to achieving the results in our business plan is the ability to sustain generating operating performance and capacity factors at expected levels since our forward sales of energy and capacity assume 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, processes or management effectiveness,
- disruptions in the transmission of electricity,
- labor disputes,
- fuel supply interruptions,
- transportation constraints,
- limitations which may be imposed by environmental or other regulatory requirements,
- permit limitations, and
- operator error or catastrophic events such as fires, earthquakes, explosions, floods, severe storms, acts of terrorism 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. In either event, to the extent that our operational targets are not met, we could have to operate higher-cost generation facilities or meet our obligations through higher-cost open market purchases.

Challenges associated with retention of a qualified workforce could adversely impact our businesses.

Our operations depend on the retention of a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. These challenges may include the lack of appropriate replacements, the loss of institutional and industry knowledge and the increased costs to hire and train new personnel. This has the potential to become more critical over the next several years as a growing number of employees become eligible to retire.

In addition, because a significant portion of our employees are covered under collective bargaining agreements, 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.

Our receipt of payment of receivables related to our domestic leveraged leases is dependent upon the credit quality and the ability of lessees to meet their obligations.

Our receipt of payments of equity rent, debt service and other fees related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors. The factors which may impact future lease cash flow include, but are not limited to, new environmental legislation regarding air quality and other discharges in the process of generating electricity, market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments, overall financial condition of lease counterparties and the quality and condition of assets under lease. If a lessee were to default, we could potentially be required to impair our current investment balances.

Table of Contents

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, Power and PSE&G

None.

ITEM 2. PROPERTIES

Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Table of Contents

Generation Facilities

Power

As of December 31, 2013, Power's share of summer installed fossil and nuclear generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	620	100%	620	Coal/Gas	Load Following
Mercer	NJ	632	100%	632	Coal/Gas	Load Following
Sewaren	NJ	453	100%	453	Gas	Load Following
Keystone (A)	PA	1,711	23%	391	Coal	Base Load
Conemaugh (A)	PA	1,711	23%	385	Coal	Base Load
Bridgeport Harbor	CT	383	100%	383	Coal	Load Following
New Haven Harbor	CT	448	100%	448	Oil	Load Following
Total Steam		5,958		3,312		
Nuclear:						
Hope Creek	NJ	1,178	100%	1,178	Nuclear	Base Load
Salem 1 & 2	NJ	2,365	57%	1,358	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,251	50%	1,125	Nuclear	Base Load
Total Nuclear		5,794		3,661		
Combined Cycle:						
Bergen	NJ	1,188	100%	1,188	Gas	Load Following
Linden	NJ	1,230	100%	1,230	Gas	Load Following
Bethlehem	NY	756	100%	756	Gas	Load Following
Kalaeloa	HI	208	50%	104	Oil	(C)
Total Combined Cycle		3,382		3,278		
Combustion Turbine:						
Essex	NJ	617	100%	617	Gas	Peaking
Edison	NJ	516	100%	516	Gas	Peaking
Kearny	NJ	463	100%	463	Gas	Peaking
Burlington	NJ	560	100%	560	Oil/Gas	Peaking
Linden	NJ	340	100%	340	Gas	Peaking
Mercer	NJ	115	100%	115	Oil	Peaking
Sewaren	NJ	105	100%	105	Oil	Peaking
Bergen	NJ	21	100%	21	Gas	Peaking
National Park	NJ	21	100%	21	Oil	Peaking
Salem 3	NJ	38	57%	22	Oil	Peaking
New Haven Harbor	CT	130	100%	130	Gas/Oil	Peaking
Bridgeport Harbor	CT	17	100%	17	Oil	Peaking
Total Combustion Turbine		2,943		2,927		
Pumped Storage:						
Yards Creek (D)	NJ	400	50%	200		Peaking
Total Power Plants		18,477		13,378		

(A) Operated by GenOn Northeast Management Company
(B) Operated by Exelon Generation
(C) Contracted under a power purchase agreement

(D) Operated by Jersey Central Power & Light Company

Table of Contents

As of December 31, 2013, Power also owned and operated 88 MW of photovoltaic solar generation facilities in various states. In December 2013, Power agreed to acquire a 4 MW solar project in Shasta, California. The project is expected to be placed into service by mid-2014.

PSE&G

As of December 31, 2013, PSE&G had 79 MW of installed solar capacity throughout New Jersey.

Transmission and Distribution Facilities

PSE&G

As of December 31, 2013, PSE&G's electric transmission and distribution system included 23,810 circuit miles, of which 8,235 circuit miles were underground, and 842,992 poles, of which 547,998 poles were jointly-owned. Approximately 100% of this property is located in New Jersey.

In addition, as of December 31, 2013, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2013, the daily gas capacity of PSE&G's 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,790,420 therms (270,914,563 cubic feet on an equivalent basis of 100,000 Btu/therm and 1,030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	772,500
Camden LPG	Camden, NJ	384,000
Central LPG	Edison, NJ	839,040
Harrison LPG	Harrison, NJ	794,880
Total		2,790,420

As of December 31, 2013, PSE&G owned and operated 17,758 miles of gas mains, owned 12 gas distribution headquarters and two sub-headquarters, all in four operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 62 natural gas metering and regulating stations, all located in New Jersey, of which 26 were located on land owned by customers or natural gas pipeline suppliers and were operated under lease, easement or other similar arrangement. In some instances, the pipeline companies owned portions of the metering and regulating facilities.

PSE&G's First and Refunding Mortgage, securing 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.

In addition, as of December 31, 2013, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 25,103 megavolt-amperes (MVA) and 246 substations with an aggregate installed capacity of 8,179 MVA. In addition, four of our substations in New Jersey having an aggregate installed capacity of 109 MVA were operated on leased property.

ITEM 3. LEGAL PROCEEDINGS

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

Superstorm Sandy

For a discussion of the lawsuit in New Jersey state court related to recoveries for property damage under PSEG's insurance policies, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

Table of Contents

Environmental Matters

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

(1) Various Spill Act directives were issued by the NJDEP to potentially responsible parties (PRPs), including PSE&G with respect to the PJP Landfill in Jersey City, Hudson County, New Jersey, ordering payment of costs associated with operation and maintenance, interim remedial measures and a Remedial Investigation and Feasibility Study (RI/FS) in excess of $25 million. The directives also sought reimbursement of the NJDEP's past and future oversight costs and the costs of any future remedial action.

(2) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a PRP. A Final Remedial Design Report was submitted to the EPA in September of 2002. This document presented the design details of the EPA's selected remediation remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement a negotiated EPA selected remediation remedy. The PRP group implementation of the remedy was completed in 2010. Although subject to EPA approval and oversight, long term monitoring activities designed to demonstrate the effectiveness of the implemented remedy are planned through 2018 at an estimated cost of $2.8 million.

(3) The Klockner Road site is located in Hamilton Township, Mercer County, New Jersey, and occupies approximately two acres on PSE&G's Trenton Switching Station property. In 1996, PSE&G entered into a memorandum of agreement with the NJDEP for the Klockner Road site pursuant to which PSE&G conducted an RI/FS and remedial action at the site to address the presence of soil and groundwater contamination. Anticipated future activities at the site include the filing of certification(s) with the NJDEP once every two years regarding the effectiveness of engineering and institutional controls, quarterly groundwater monitoring for several years and the installation of additional off-site groundwater monitoring wells as directed by the NJDEP.

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

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

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

Table of Contents

PART II

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

Our common stock is listed on the New York Stock Exchange, Inc. As of December 31, 2013, there were 72,713 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2008 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.

	2008	2009	2010	2011	2012	2013
PSEG	$100.00	$118.86	$118.75	$128.49	$124.58	$136.24
S&P 500	$100.00	$126.37	$145.36	$148.44	$172.08	$227.69
DJ Utilities	$100.00	$112.42	$119.66	$143.10	$145.38	$163.80
S&P Electrics	$100.00	$103.34	$106.88	$129.16	$128.39	$138.44

Table of Contents

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

Common Stock	High	Low	Dividend per Share
2013			
First Quarter	$34.34	$29.78	$0.360
Second Quarter	$36.61	$31.21	$0.360
Third Quarter	$34.53	$31.66	$0.360
Fourth Quarter	$34.32	$31.65	$0.360
2012			
First Quarter	$33.25	$29.59	$0.355
Second Quarter	$32.51	$28.92	$0.355
Third Quarter	$34.07	$31.19	$0.355
Fourth Quarter	$33.36	$29.05	$0.355

On February 18, 2014, our Board of Directors approved a $0.370 per share common stock dividend for the first quarter of 2014. This reflects an indicated annual dividend rate of $1.48 per share.
The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation award grants during the fourth quarter of 2013:

Three Months Ended December 31, 2013	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$—
November 1-November 30	4,000	$33.01
December 1-December 31	—	$—

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2013:

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	2,615,166	$34.43	16,508,170
Employee Stock Purchase Plan	—	$—	3,589,032
Total	2,615,166	$34.43	20,097,202

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data—Note 18. Stock Based Compensation.
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—Overview of 2013 and Future Outlook.
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—Overview of 2013 and Future Outlook.

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 (Notes).

PSEG					
Years Ended December 31,	2013	2012	2011	2010	2009
	Millions, except Earnings per Share				
Operating Revenues	$9,968	$9,781	$11,079	$11,793	$12,035
Income from Continuing Operations (A)	$1,243	$1,275	$1,407	$1,557	$1,594
Net Income	$1,243	$1,275	$1,503	$1,564	$1,592
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$2.46	$2.52	$2.78	$3.08	$3.15
Diluted (A)	$2.45	$2.51	$2.77	$3.07	$3.14
Net Income					
Basic	$2.46	$2.52	$2.97	$3.09	$3.15
Diluted	$2.45	$2.51	$2.96	$3.08	$3.14
Dividends Declared per Share	$1.44	$1.42	$1.37	$1.37	$1.33
As of December 31,					
Total Assets	$32,522	$31,725	$29,821	$29,909	$28,678
Long-Term Obligations (B)	$7,872	$6,701	$7,482	$7,847	$7,679

`

(A) Income from Continuing Operations for 2011 includes an after-tax charge of $170 million related to certain leveraged leases.

(B) Includes capital lease obligations.

Power and PSE&G

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

39

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), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G). Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, its principal direct wholly owned subsidiaries, which are:

- Power, our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States, and
- PSE&G, our public utility company which provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which effective January 1, 2014 operates the Long Island Power Authority's transmission and distribution system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors 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 2013 and key factors that we expect will drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the Related Notes to Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

OVERVIEW OF 2013 AND FUTURE OUTLOOK

2013 Overview

Our business plan is designed to manage the risks associated with fluctuating commodity prices and changes in customer demand as we invest to achieve growth in light of market, regulatory and economic trends. In 2013, we continued our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in transmission and distribution infrastructure projects with a consequent rebalancing of our business mix and greater diversification of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to capitalize on market opportunities as they arise in the locations in which we operate.

Table of Contents

Financial Results

The results for PSEG, Power and PSE&G for the years ended December 31, 2013 and 2012 are presented below:

	Years Ended December 31,	
	2013	2012
Earnings (Losses)	Millions, except per share data	
Power	$644	$666
PSE&G	612	528
Other	(13)	81
PSEG Net Income	$1,243	$1,275
Earnings Per Share (Diluted)		
PSEG Net Income	$2.45	$2.51

Our $32 million 2013 over 2012 decrease in Net Income was due primarily to higher Operations and Maintenance (O&M) costs in 2013 related to planned outage work and higher mark-to-market losses at Power. In addition, 2012 Net Income included recoveries from one of Energy Holdings' leverage lease investments, and a one-time benefit from the settlement of the 1997-2006 Internal Revenue Service audits in 2012. These factors were partially offset by higher market prices, fuel supply cost savings and increased capacity pricing at Power, and higher transmission revenues at PSE&G. For a more detailed discussion of our financial results, see Results of Operations.

Power's results also benefited from access to low-cost natural gas from the Marcellus region during the latter half of 2013 through its existing firm pipeline transportation and storage contracts. Power manages these contracts for the benefit of PSE&G's customers through the basic gas supply service (BGSS) arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When the customers' demand for gas is lower, which frequently occurs outside of the winter usage period, Power can use the remaining available pipeline transportation to make third party sales and supply the Marcellus gas to its generating units in New Jersey.

At PSE&G, our regulated utility, we continued to invest capital in transmission and distribution infrastructure projects aimed at maintaining the reliability of our service to our customers. PSE&G's results for 2013 reflect the favorable impacts from these investments. In January 2014, we filed a Modified 2014 Annual Formula Rate Update with the Federal Energy Regulatory Commission (FERC) in December 2013 which provides for approximately $171 million in increased annual transmission revenues effective January 1, 2014. Over the past few years, these types of investments have altered the business mix of PSEG's overall results of operations to reflect a higher percentage contribution by PSE&G.

Regulatory, Legislative and Other Developments

In developing and implementing our strategy of operational excellence, financial strength and disciplined investment, we monitor significant regulatory and legislative developments. Competitive wholesale power market design is of particular importance to our results and we continue to advocate for policies and rules that promote competitive electricity markets. This includes opposing efforts by states to subsidize generation and supporting rule changes which we believe are necessary to avoid artificial price suppression and other distortions in the energy and capacity markets. Federal court decisions in New Jersey and Maryland invalidated legislation in those states which sought to subsidize generation. For a more detailed discussion of the status of these efforts, refer to Item 1. Business—Regulatory Issues—Federal Regulation.

We continue to advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. In particular, the EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology (MACT) rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented. These matters are discussed in Item 1. Business—Environmental Matters.

As discussed in further detail under Item 1. Business—Regulatory Issues—Federal Regulation, the FERC's rules under Order 1000 altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are challenging the FERC's determination in court as we do not believe that the FERC sufficiently justified its decision to alter this right embedded in the FERC-approved contracts and tariffs. At the same time, the FERC's action presents opportunities for us to construct transmission outside of our service territory.

Table of Contents

In the fourth quarter of 2012, we were severely impacted by Superstorm Sandy, which resulted in the highest level of customer outages in our history. We sustained significant damage to some of our generation, transmission and distribution facilities. The New Jersey Board of Public Utilities (BPU) issued an order allowing PSE&G to defer actually incurred prudent, incremental storm restoration costs not otherwise recoverable through base rates or insurance. Proceedings at the BPU on the prudency and recovery of storm-related costs are pending. Power also incurred significant storm-related expenses, primarily for repairs at certain of its coal and gas-fired generating stations in 2013. We are seeking recovery from our insurers for the property damage, above our self-insured retentions; however, no assurances can be given relative to the timing or amount of any such recovery. In June 2013, we filed suit against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses resulting from damage caused by Superstorm Sandy's storm surge. For more detailed information, refer to Item 1. Business—Regulatory and Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for additional information.

In February 2013, we filed a petition with the BPU describing our Energy Strong program, consisting of $3.9 billion of proposed improvements we recommend making to our gas and electric distribution systems over a ten-year period to improve resiliency. In the petition, we sought approval for $2.6 billion of the $3.9 billion of investments over an initial five- year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. We cannot predict the outcome of this pending proceeding. As proposed, we believe that the rate impacts of the Energy Strong program will be significantly muted as a result of scheduled reductions to customer bills that will be taking place over the next few years and assuming continued low gas prices. See Item 1. Business—State Regulation for additional details.

During 2013, we continued to execute our five major regional transmission projects for which we were assigned construction responsibility by PJM. In December 2013, we were assigned construction by PJM of a new transmission project that will provide a double-circuit 345kV line in the Bergen-Linden Corridor to maintain reliability. See Item 1. Business—Business Operations and Strategy—PSE&G for additional information.

On January 1, 2014, we commenced operation of the Long Island Power Authority (LIPA) transmission and distribution (T&D) system under a twelve-year contract with opportunity to extend for an additional eight years. Also, beginning in 2015, Power will provide fuel procurement and power management services to LIPA under separate agreements. See Item 1. Business—Business Operations and Strategy—Other for additional details.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In 2013, our

- total nuclear fleet achieved an average capacity factor in excess of 90% for the ninth consecutive year,
- outstanding performance allowed us to increase generation to meet loads,
- construction of transmission and solar projects proceeded on schedule and within budget, and
- utility ranked nationally in the top quartile for safety and reliability.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2013 as we:

- had cash on hand of $493 million as of December 31, 2013,
- extended the expiration date of approximately half of our credit facilities, and maintained substantial liquidity and solid investment grade credit ratings, as evidenced by the recent credit rating upgrades by Standard & Poor's (S&P) of PSEG, Power and PSE&G and upgrade by Moody's of PSE&G as disclosed below in Liquidity and Capital Resources—Credit Ratings,
- completed pension funding for 2013, which when combined with strong market results and a higher discount rate, resulted in a year-end ratio of the value of our pension plan assets to our projected pension benefit obligation of 106 percent,
- issued bonds at historically low rates at PSE&G to refinance its maturing debt and fund its capital program, and
- paid an annual dividend of $1.44 and increased our indicated annual dividend for 2014 to $1.48.

We expect to be able to fund our proposed Energy Strong program with internally generated cash and external debt financing.

Table of Contents

Disciplined Investment

We utilize rigorous investment criteria when deploying capital, and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In 2013 we:

- made additional investments in transmission infrastructure projects of $1.7 billion,
- continued to execute our existing BPU-approved utility programs,
- obtained approval from the BPU to increase our spending up to $247 million and $199 million under our Solar 4 All Extension and Solar Loan III investment programs, respectively,
- approved additional investments in our existing generation facilities to increase output and improve efficiency, and
- commenced operation of a newly constructed 19 MW solar project in Arizona.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a difficult economy and cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments and to respond to the issues and challenges described below. In order to do this, we must continue to:

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully re-contract our open supply positions,
- execute our capital investment program, including investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to protect competition and achieve appropriate Reliability Pricing Model (RPM) and basic generation service (BGS) pricing,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

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

- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- uncertainty in the national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer demand,
- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- the aftermath of Hurricane Irene and Superstorm Sandy, including addressing the BPU's review of performance and communications, as well as cost recovery and opportunities for investment in system strengthening, including our proposed Energy Strong program, and
- delays and other obstacles that might arise in connection with the construction of our transmission and distribution projects, including in connection with permitting and regulatory approvals.

RESULTS OF OPERATIONS

	Years Ended December 31,		
	2013	2012	2011
Earnings (Losses)	Millions		
Power (A)	$644	$666	$1,013
PSE&G (A)	612	528	521
Other (B)	(13)	81	(127)
PSEG Income from Continuing Operations	1,243	1,275	1,407
Income (Loss) from Discontinued Operations, Including Gain on Disposal (C)	—	—	96
PSEG Net Income	$1,243	$1,275	$1,503

	Years Ended December 31,		
Earnings Per Share (Diluted)	2013	2012	2011
PSEG Income from Continuing Operations	$2.45	$2.51	$2.77
Income from Discontinued Operations, Including Gain on Disposal (C)	—	—	0.19
PSEG Net Income	$2.45	$2.51	$2.96

(A) Power's results in 2013 and 2012 include after-tax expenses, net of insurance recoveries, of $32 million and $39 million, respectively, and PSE&G's results in 2012 include after-tax expenses of $24 million for O&M costs due to severe damage caused by Superstorm Sandy. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

(B) Other includes an after-tax charge of $170 million taken in 2011 at Energy Holdings related to the reserve for assets underlying a leveraged lease receivable. See Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

(C) See Item 8. Financial Statements and Supplementary Data—Note 4. Discontinued Operations and Dispositions.

The 2013 year-over-year decrease in our Income from Continuing Operations/Net Income was driven primarily by:

- lower volumes of electricity sold under Power's basic generation service (BGS) contracts at lower average prices,
- lower volumes of wholesale load contracts in the PJM and New England (NE) regions,
- unfavorable amounts related to the mark-to-market (MTM) activity, discussed below,
- higher generation costs due to higher fuel costs,
- higher planned outage and maintenance costs at certain of our fossil and nuclear plants, partially offset by cost control measures,
- the absence of the gain on the Dynegy settlement in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables), and
- higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes).

These decreases were largely offset by

- higher capacity revenues in the PJM region resulting from higher average prices as well as higher generation sold primarily in the PJM region,
- higher average gas prices on increased sales to third party customers, and
- higher revenues due to increased investments in transmission projects.

Table of Contents

The 2012 year-over-year decrease in our Income from Continuing Operations was driven by:

- lower average pricing and volumes for electricity sold under our BGS contracts,
- lower average prices realized on generation sold into various power pools,
- unfavorable amounts related to the MTM activity, discussed below,
- higher O&M costs due to severe damage caused by Superstorm Sandy to our transmission and distribution system throughout our service territory as well as to some of our generation infrastructure in the northern part of New Jersey.

The decreases were partially offset by:

- the absence of the $170 million after-tax charge taken in 2011 on leveraged leases related to Dynegy and the settlement proceeds received in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables), and
- higher transmission revenues at PSE&G.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. Net realized gains, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income and Deductions, and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance Expense, as well as the depreciation related to the ARO asset. In September 2012, we restructured a portion of our NDT Fund and realized gains of $59 million. The investments were transitioned to new investment managers.

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

The combined after-tax impact on Income from Continuing Operations for the years ended December 31, 2013, 2012 and 2011 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2013	2012	2011
	Millions, after tax		
NDT Fund and Related Activity	$40	$52	$50
Non-Trading MTM Gains (Losses)	$(74)	$(10)	$107

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, Power and PSE&G, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 24. Related-Party Transactions.

Table of Contents

	Years Ended December 31,			Increase / (Decrease) 2013 vs. 2012		Increase / (Decrease) 2012 vs. 2011	
	2013	2012	2011	Millions	%	Millions	%
	Millions						
Operating Revenues	$9,968	$9,781	$11,079	$187	2	$(1,298)	(12)
Energy Costs	3,536	3,719	4,747	(183)	(5)	(1,028)	(22)
Operation and Maintenance	2,887	2,632	2,481	255	10	151	6
Depreciation and Amortization	1,178	1,054	976	124	12	78	8
Income from Equity Method Investments	11	12	4	(1)	(8)	8	N/A
Other Income and (Deductions)	159	162	135	(3)	(2)	27	20
Other-Than-Temporary Impairments	12	18	22	(6)	(33)	(4)	(18)
Interest Expense	402	423	475	(21)	(5)	(52)	(11)
Income Tax Expense	812	736	977	76	10	(241)	(25)
Income from Discontinued Operations, including Gain on Disposal, net of tax	—	—	96	—	—	(96)	(100)

For a detailed explanation of the variances, see the following discussions for Power and PSE&G.

Power

Power	Years Ended December 31,			Increase / (Decrease) 2013 vs. 2012		Increase / (Decrease) 2012 vs. 2011	
	2013	2012	2011	Millions	%	Millions	%
	Millions						
Operating Revenues	$5,063	$4,873	$6,150	$190	4	$(1,277)	(21)
Energy Costs	2,496	2,381	3,044	115	5	(663)	(22)
Operation and Maintenance	1,224	1,127	1,105	97	9	22	2
Depreciation and Amortization	273	242	228	31	13	14	6
Income from Equity Method Investments	16	15	14	1	7	1	7
Other Income (Deductions)	105	111	111	(6)	(5)	—	—
Other-Than-Temporary Impairments	12	18	20	(6)	(33)	(2)	(10)
Interest Expense	116	132	175	(16)	(12)	(43)	(25)
Income Tax Expense	419	433	690	(14)	(3)	(257)	(37)
Income (Loss) from Discontinued Operations, Including Gain on Disposal	—	—	96	—	—	(96)	(100)

Year Ended December 31, 2013 as compared to 2012

Operating Revenues increased $190 million due to changes in generation and supply revenues.

Generation Revenues increased $102 million due primarily to

- an increase of $341 million due to higher capacity revenues resulting from higher average auction prices and an increase in operating reserve revenues in PJM, and

- higher net revenues of $36 million due primarily to higher generation sold in the PJM and NE regions partly offset by higher MTM losses in 2013 resulting from an increase in prices on forward positions in the PJM and NE regions,

46

Table of Contents

- partially offset by a decrease of $155 million due primarily to lower volumes of electricity sold under our BGS contracts and lower average pricing, and
- a net decrease of $120 million due to lower volumes on wholesale load contracts in the PJM and NE regions.

Gas Supply Revenues increased $88 million due primarily to

- a net increase of $40 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2013 winter heating season, partially offset by lower average gas prices, and
- a net increase of $48 million due primarily to higher average gas prices and higher sales volumes to third party customers.

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 $115 million due to

- Gas costs increased $40 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due to colder average temperatures during the 2013 winter heating season and higher volumes on third party sales, partially offset by lower average gas inventory costs.
- Generation costs increased $75 million due primarily to $84 million of higher fuel costs, reflecting higher average realized natural gas prices, higher nuclear fuel costs and the utilization of higher volumes of coal and oil, partially offset by lower average coal prices and lower average unrealized natural gas prices on forward positions.

Operation and Maintenance increased $97 million due primarily to

- higher planned outage and maintenance costs in 2013, mainly at our gas-fired Bethlehem Energy Center (BEC) plant in New York, Bergen gas-fired plant in New Jersey, Linden gas-fired plant in New Jersey and 23%-owned Conemaugh coal-fired plant in Pennsylvania, partially offset by lower storm costs in 2013, and
- higher outage costs at our nuclear generating facilities, primarily at our 100%-owned Hope Creek station.

Depreciation and Amortization increased $31 million due primarily to a higher depreciable asset base at Fossil and Nuclear, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012, completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012, and placing two solar facilities into service in the fourth quarter of 2012. In addition, an update to the nuclear asset retirement obligation became effective in November 2012, causing higher depreciation in 2013.

Income from Equity Method Investments experienced no material change.

Other Income (Deductions) decreased $6 million due primarily to lower NDT Fund realized gains in 2013, partially offset by lower NDT Fund realized losses in 2013. In addition, we recognized a loss on the extinguishment of debt in 2012.

Other-Than-Temporary Impairments decreased $6 million due to lower impairments on the NDT Fund in 2013.

Interest Expense decreased $16 million due primarily to a decrease of $23 million resulting from the maturity of $300 million of 2.50% of Senior Notes in April 2013, and the early redemptions of $250 million of 5.00% medium term notes and various tax-exempt bonds in December 2012, partially offset by higher interest costs of $6 million in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense decreased $14 million in 2013 due primarily to lower pre-tax income.

Year ended December 31, 2012 as compared to 2011

Operating Revenues decreased $1,277 million due to changes in generation and supply revenues.

Generation Revenues decreased $974 million due primarily to

- lower net revenues of $564 million due primarily to lower average realized prices for our generation sold into the PJM and NY power pools and MTM losses due from the realization of prior year unrealized gains and adverse changes in unrealized prices in 2012 for forward positions,
- a decrease of $264 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts, primarily as a result of warmer winter weather in 2012 as well as customer migration, and
- a net decrease of $154 million due to lower volumes on wholesale load contracts in the PJM and NE regions,

47

Table of Contents

- partially offset by a net increase of $7 million in other revenues consisting of higher net capacity revenues, partially offset by lower operating reserve, ancillary and RMR revenues.

Gas Supply Revenues decreased $336 million due primarily to

- a decrease of $306 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in 2012 due to warmer average temperatures during the first quarter of 2012, and
- a net decrease of $31 million due primarily to lower average prices, partially offset by higher sales volumes to third party customers.

Trading Revenues increased $33 million in 2012 due to the discontinuation of trading activities in the second quarter of 2011. As a result, the increase is due primarily to the absence of losses on electric energy supply contracts recognized in 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power’s obligation under its BGSS contract with PSE&G. Energy Costs decreased $663 million due to

- Gas costs decreased $312 million, principally related to obligations under the BGSS contract, reflecting lower average gas inventory costs coupled with lower sales volumes in 2012 due primarily to warmer average temperatures during the first quarter of 2012.
- Generation costs decreased $351 million due primarily to $227 million of lower fuel costs, reflecting the utilization of lower volumes of coal and lower average natural gas prices, partially offset by the utilization of higher volumes of natural gas and higher nuclear fuel prices in 2012. The decrease was also attributable to $152 million of lower energy purchases, primarily in the PJM region as a result of lower load contract volumes in 2012, and $31 million of lower emission charges due to lower coal generation in the PJM and NE regions and impairment charges recorded in 2011 related to excess SO_2 emission allowances. These decreases were partially offset by an increase of $59 million due primarily to higher congestion costs in the PJM region.

Operation and Maintenance increased $22 million due primarily to

- an increase of $85 million due to damage from Superstorm Sandy for repairs to certain of our generation plants, primarily those in our fossil fleet, and to recognize the estimated loss of use of fossil materials and supplies, partially offset by a $19 million insurance recovery, and
- a net increase of $64 million due to higher refueling costs in 2012 for refueling outages at our 100%-owned Hope Creek nuclear unit and our 57%-owned Salem Unit 2 as compared to refueling outages for both of our 57%-owned Salem nuclear units in 2011,
- partially offset by a net decrease of $109 million largely due to lower fossil planned outages in 2012 and lower maintenance costs, principally at our BEC station, our gas-fired Bergen and Linden facilities and coal/gas-fired Hudson and Mercer plants in New Jersey, and 23%-owned Conemaugh plant, as well as to the absence of costs incurred for the cancellation and renegotiation of a major contractual agreement for parts and services in 2011.

Depreciation and Amortization increased $14 million due primarily to higher depreciable asset bases at Fossil and Nuclear, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012 and completion of the steam path retrofit upgrades at our co-owned Peach Bottom Units 2 and 3 in October 2012 and October 2011, respectively.

Income from Equity Method Investments experienced no material change.

Other Income (Deductions) experienced no material change.

Other-Than-Temporary Impairments decreased $2 million due to lower impairments in 2012 on the NDT and Rabbi Trust Funds.

Interest Expense decreased $43 million due primarily to a decrease of $55 million resulting primarily from the maturity of $606 million of 7.75% Senior Notes in early April 2011 and the early redemption of $600 million of 6.95% Senior Notes in December 2011, partially offset by increases of $12 million due to two $250 million Senior Notes issuances in September 2011 and $3 million in higher interest costs since interest capitalization ceased for our Kearny and New Haven projects in their June 2012 in-service date.

Income Tax Expense decreased $257 million in 2012 due primarily to lower pre-tax income.

Table of Contents

Income (Loss) from Discontinued Operations

In 2011, we sold our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions. In March 2011, we completed the sale of one plant for proceeds of $352 million at an after-tax gain of $54 million. In July 2011, we completed the sale of the second plant for proceeds of $335 million at an after-tax gain of $25 million. The results of operations for both plants for 2011, including the gain on the sales of the plants, are included in this category. See Item 8. Financial Statements and Supplementary Data—Note 4. Discontinued Operations and Dispositions for additional information.

PSE&G

PSE&G	Years Ended December 31, 2013	2012	2011	Increase / (Decrease) 2013 vs. 2012 Millions	%	Increase / (Decrease) 2012 vs. 2011 Millions	%
	Millions						
Operating Revenues	$6,655	$6,626	$7,326	$29	—	$(700)	(10)
Energy Costs	2,841	3,159	3,951	(318)	(10)	(792)	(20)
Operation and Maintenance	1,639	1,508	1,372	131	9	136	10
Depreciation and Amortization	872	778	719	94	12	59	8
Taxes Other Than Income Taxes	68	98	133	(30)	(31)	(35)	(26)
Other Income (Deductions)	51	47	21	4	9	26	N/A
Other-Than-Temporary Impairments	—	—	1	—	—	(1)	(100)
Interest Expense	293	295	310	(2)	(1)	(15)	(5)
Income Tax Expense	381	307	340	74	24	(33)	(10)

Year Ended December 31, 2013 as compared to 2012

Operating Revenues increased $29 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $223 million due primarily to an increase in transmission revenues.

- Transmission revenues were $184 million higher due to increased investments in transmission projects.
- Gas distribution revenues increased $24 million due primarily to higher sales volumes of $70 million, higher Capital Infrastructure Program (CIP) related revenue of $23 million and higher revenue from Solar and Energy Efficiency Recovery Charges (formerly RRC and currently Green Program Recovery Charges (GPRC)) of $5 million, partially offset by lower Weather Normalization Clause (WNC) revenue of $67 million due to more normal weather compared to the prior year and lower Transitional Energy Facilities Assessment (TEFA) revenue of $7 million due to a lower TEFA rate.
- Electric distribution revenues increased $15 million due primarily to higher GPRC of $37 million and higher CIP related revenue of $11 million, partially offset by lower TEFA revenue of $23 million due to a lower TEFA rate and lower sales volumes of $10 million.

Clause Revenues increased $110 million due primarily to higher Securitization Transition Charge (STC) revenues of $51 million, higher Societal Benefit Charges (SBC) of $47 million and a higher Solar Pilot Recovery Charge (SPRC) of $11 million. The changes in STC, SBC and SPRC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC or SPRC collections.

Commodity Revenue decreased $318 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $308 million due primarily to $169 million in lower BGS revenues and $139 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and collections of Non-Utility Generation Charges (NGC) due primarily to lower prices. BGS sales decreased 4% due primarily to customer migration to third party suppliers (TPS) and weather.

- Gas revenues decreased $10 million due to lower BGSS prices of $121 million, partially offset by higher BGSS volumes of $111 million. The average price of natural gas was 12% lower in 2013 than in 2012.

Table of Contents

Other Operating Revenues increased $14 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Operating Expenses

Energy Costs decreased $318 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $308 million or 14% due to $214 million in lower BGS and NUG volumes, $35 million of lower BGS prices, and $59 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs decreased $10 million or 1% due to $121 million or 12% in lower prices, partially offset by $111 million or 11% in higher sales volumes due primarily to weather.

Operation and Maintenance increased $131 million, of which the most significant components were

- a $131 million increase in costs related to SBC, GPRC and CIP,
- a $24 million increase in transmission related costs, and
- a $10 million increase in appliance service costs,
- partially offset by the absence of $40 million in transmission and distribution storm damages in 2012,
- a $10 million decrease in pension and other postretirement benefits (OPEB) expenses, and
- an $11 million decrease in gas bad debt expense.

Depreciation and Amortization increased $94 million due primarily to

- a $59 million increase in amortization of Regulatory Assets, and
- a $33 million increase in additional plant in service.

Taxes Other Than Income Taxes decreased $30 million due to a lower TEFA rate, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $4 million was due primarily to

- a $5 million increase in solar loan interest income,
- partially offset by a $1 million decrease in Rabbi Trust interest and gains.

Interest Expense experienced no material change.

Income Tax Expense increased $74 million due primarily to higher pre-tax income and the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012.

Year ended December 31, 2012 as compared to 2011

Operating Revenues decreased $700 million due to changes in delivery, clause, commodity and other operating revenues.

Commodity Revenue decreased $792 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $488 million due primarily to $431 million in lower BGS revenues and $57 million in lower revenues from the sale of NUG energy and collections of NGC due primarily to lower prices. BGS sales decreased 12% due primarily to customer migration to TPS; in contrast, delivery sales decreased only 1%.
- Gas revenues decreased $304 million due to lower BGSS volumes of $115 million and lower BGSS prices of $189 million. The average price of natural gas was 15% lower in 2012 than in 2011.

Delivery Revenues increased $83 million due primarily to an increase in transmission revenues.

- Transmission revenues were $83 million higher due to increased investments in transmission projects.
- Electric distribution revenues decreased $6 million due primarily to lower TEFA revenue of $22 million due to a lower TEFA rate and lower sales volumes of $13 million, partially offset by higher GPRC revenue of $20 million and higher CIP revenue of $9 million.

Table of Contents

- Gas distribution revenues increased $4 million due primarily to higher WNC revenue of $52 million and higher CIP revenue of $8 million, partially offset by lower sales volumes of $43 million, and lower TEFA revenue of $13 million due to a lower TEFA rate.

Clause Revenues increased $12 million due primarily to higher STC revenues of $19 million, partially offset by lower SBC of $6 million and a Margin Adjustment Clause (MAC) of $2 million. The changes in STC, SBC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, STC or MAC collections.

Operating Expenses

Energy Costs decreased $792 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $488 million or 18% due to $258 million in lower BGS and NUG volumes, $202 million of lower BGS prices, and $28 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs decreased $304 million or 24% due to $115 million or 9% in lower sales volumes due primarily to weather and $189 million or 15% in lower prices.

Operation and Maintenance increased $136 million, of which the most significant components were

- a $32 million increase in costs recognized related to SBC, GPRC and CIP,
- a $27 million increase in pension and OPEB expenses,
- a $17 million increase in storm damages,
- a $10 million increase in transmission related costs, and
- a $7 million increase in payroll costs.

Depreciation and Amortization increased $59 million due primarily to

- a $39 million increase in amortization of Regulatory Assets, and
- a $21 million increase in additional plant in service.

Taxes Other Than Income Taxes decreased $35 million due to a lower TEFA rate and lower sales volumes for electric and gas.

Other Income and (Deductions) net increase of $26 million was due primarily to

- a $14 million increase in capitalized allowance for equity funds used during construction,
- an $8 million increase in solar loan interest income, and
- a $4 million increase in Rabbi Trust interest and gains.

Other-Than-Temporary Impairments experienced no material change.

Interest Expense decreased $15 million due primarily to the partial redemption of securitization debt and higher interest capitalization related to higher construction work in progress, partially offset by interest relating to the new debt issued in 2012.

Income Tax Expense decreased $33 million due primarily to changes in tax reserves related to settlement of IRS tax audits.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Financing Methodology

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

PSE&G’s sources of external liquidity include a $600 million multi-year syndicated credit facility. PSE&G’s commercial paper program is the primary vehicle for meeting seasonal, intra-month and temporary working capital needs. PSE&G does not engage in any intercompany borrowing or lending. 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 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 PSEG Services Corporation participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Long Island Electric Utility Servco LLC (ServCo), a wholly owned subsidiary of PSEG LI, 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 include multi-year syndicated credit facilities totaling $1 billion. These facilities are available to back-stop PSEG’s commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG’s credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power’s sources of external liquidity include $2.7 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Credit capacity is primarily used to provide collateral in support of Power's forward energy sale and forward fuel purchase contracts as the market prices for energy and fuel fluctuate, and to meet potential collateral postings in the event of a credit rating downgrade below investment grade. 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, 2013, our operating cash flow increased by $371 million. For the year ended December 31, 2012, our operating cash flow decreased by $770 million. The net changes were due to net changes from our subsidiaries as discussed below.

Power

Power’s operating cash flow decreased $106 million from $1,453 million to $1,347 million for the year ended December 31, 2013, as compared to 2012, primarily resulting from

- lower earnings, and
- higher tax payments,
- partially offset by a decrease of $73 million related to margin deposits, and
- a decrease of $26 million in employee benefit plan funding.

Power’s operating cash flow decreased $364 million from $1,817 million to $1,453 million for the year ended December 31, 2012, as compared to 2011, primarily resulting from lower earnings and a $172 million decrease from lower net collections of counterparty receivables, partially offset by

Table of Contents

- a decrease of $57 million in benefit plan funding,
- a $73 million decrease in spending for fuel, materials and supplies, and
- a $249 million decrease in net payment of counterparty payables.

PSE&G

PSE&G’s operating cash flow increased $389 million from $1,256 million to $1,645 million for the year ended December 31, 2013, as compared to 2012, due primarily to

- higher earnings,
- an increase of $134 million due to an increase from a net change in regulatory deferrals primarily related to BGSS gas costs and the collection of Gas Weather Normalization Charges, and
- a decrease of $47 million in benefit plan funding,
- partially offset by $114 million related to higher tax payments

PSE&G’s operating cash flow decreased $520 million from $1,776 million to $1,256 million for the year ended December 31, 2012, as compared to 2011, due primarily to

- a lower tax receipt of $484 million due to lower benefit of accelerated tax depreciation, and
- a decrease of $306 million due to lower collections from customer billings,
- partially offset by a decrease of $117 million in benefit plan funding, and
- a decrease of $88 million in net prepayments due primarily to the application of prior year prepayment carryforwards towards current year state tax liabilities.

Short-Term Liquidity

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries’ liquidity needs. Our total credit facilities and available liquidity as of December 31, 2013 were as follows:

	As of December 31, 2013		
Company/Facility	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$1,000	$8	$992
Power	2,700	170	2,530
PSE&G	600	73	527
Total	$4,300	$251	$4,049

As of December 31, 2013, 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. PSE&G’s credit facility primary use is to support its Commercial Paper Program under which as of December 31, 2013, $60 million was outstanding. Most of our credit facilities expire in 2017 and 2018. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities and Note 14. Schedule of Consolidated Debt.

Table of Contents

Long-Term Debt Financing

PSE&G has $250 million of 5.00%, Series D, Medium Term Notes and $250 million of 0.85%, Series G, Medium Term Notes both maturing in August 2014.

Power has a $44 million pollution control facilities loan servicing and securing a Pennsylvania Economic Development Financing Authority (PEDFA) bond due November 2042. The bond is backed by a three-year letter of credit that expires in November 2014. The PEDFA bond has been reclassified as debt due within the year.

For a discussion of our long-term debt transactions during 2013 and into 2014, see Item 8. Financial Statements and Supplementary Data—Note 14. Schedule of Consolidated Debt.

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 to1, and/or against retired Mortgage Bonds. As of December 31, 2013, PSE&G's Mortgage coverage ratio was 4.2 to1 and the Mortgage would permit up to approximately $2.7 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various default provisions that could result in the potential acceleration of payment under the defaulting company's agreement. We have not defaulted under these agreements.

PSEG's bank credit agreements contain cross default provisions under which events at Power or PSE&G, including payment defaults, bankruptcy events, the failure to satisfy certain final judgments or other events of default under their financing agreements, would each constitute an event of default. Under the bank credit agreements, it would be an event of default if both Power and PSE&G cease to be wholly owned by PSEG.

There are no cross default provisions to affiliates in Power's or PSE&G's credit agreements or indentures.

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.

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 at today's market prices.

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.

PSE&G is the servicer for the bonds issued by PSE&G Transition Funding LLC and PSE&G Transition Funding II LLC. Cash collected by PSE&G to service these bonds is commingled with PSE&G's other cash until it is remitted to the bond trustee each month. If PSE&G were to lose its investment grade rating, PSE&G would be required to remit collected cash daily to the bond trustee. PSE&G is prohibited from advancing its own funds to make payments related to such bonds.

Table of Contents

Common Stock Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	2013	2012	2011
Per Share	$1.44	$1.42	$1.37
in Millions	$728	$718	$693

On February 18, 2014, our Board of Directors approved a $0.370 per share common stock dividend for the first quarter of 2014. This reflects an indicated annual dividend rate of $1.48 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In April 2013, S&P upgraded the corporate credit ratings on PSEG, Power and PSE&G to BBB+ from BBB and PSE&G's Mortgage Bond rating to A from A-. PSEG's, Power's and PSE&G's outlooks were changed to stable from positive. In May 2013, Moody's published updated credit opinions on PSEG, Power and PSE&G. PSEG's, Power's and PSE&G's ratings and outlooks remained unchanged. In July 2013, Fitch published updated research on PSEG, Power and PSE&G which kept their ratings and outlooks unchanged. In January 2014, Moody’s upgraded PSE&G’s Mortgage Bond Rating from A1 to Aa3 and its commercial paper rating from P2 to P1. PSE&G’s outlook is stable.

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

(A) Moody’s ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1 (highest) to D (lowest) for short-term securities.

Other Comprehensive Income

For the year ended December 31, 2013, we had Other Comprehensive Income of $293 million on a consolidated basis. Other Comprehensive Income was due primarily to a $55 million increase in net unrealized gains related to Available-for-Sale Securities, and a $247 million decrease in our consolidated liability for pension and postretirement benefits and was partially

55

Table of Contents

offset by $9 million of unrealized losses on derivative contracts accounted for as hedges. See Item 8. Financial Statements and Supplementary Data—Note 21. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

CAPITAL REQUIREMENTS

It is expected 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 amounts are subject to change, based on various factors. We will continue to approach non-regulated solar and other renewables investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2014	2015	2016
Power:		Millions	
Baseline	$210	$210	$210
Environmental/Regulatory	85	55	35
Fossil Growth Opportunities	40	15	—
Nuclear Expansion	140	85	25
Solar Expansion	5	—	—
Total Power	$480	$365	$270
PSE&G:			
Transmission			
Reliability Enhancements	$1,435	$1,290	$975
Facility Replacement	110	125	135
Support Facilities	10	15	15
Distribution			
Reliability Enhancements	90	85	95
Facility Replacement	145	160	160
Support Facilities	45	45	45
New Business	155	155	160
Environmental/Regulatory	40	40	40
Renewables	125	125	55
Total PSE&G	$2,155	$2,040	$1,680
Services	45	35	25
Total PSEG	$2,680	$2,440	$1,975

Power

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

- Baseline—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Fossil Growth Opportunities—investments associated with upgrades to increase efficiency and output at combined cycle plants.
- Nuclear Expansion—investments associated with certain Nuclear capital projects, primarily at existing facilities designed to increase operating output.

In 2013, Power made $415 million of capital expenditures, excluding $194 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear.

Table of Contents

PSE&G

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

- Reliability Enhancements—investments made to maintain the reliability and efficiency of the system or function.
- Facility Replacement—investments made to replace systems or equipment in kind.
- Support Facilities—ancillary equipment needed to support the business lines, such as computers, office furniture and buildings and structures housing support personnel or equipment/inventory.
- New Business—investments made in support of new business (e.g. to add new customers).
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Renewables—investments made in response to regulatory or legal mandates relating to renewable energy.

In 2013, PSE&G made $2,207 million of capital expenditures, including $2,175 million of investment in plant, primarily for transmission and distribution system reliability and $32 million in solar loan investments. This does not include expenditures for certain energy efficiency and renewable programs of $8 million or cost of removal, net of salvage, of $93 million, which are included in operating cash flows.

Additional Projects

In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our electric and gas distribution systems over a ten year period to improve resiliency for the future. In this petition, we sought approval to invest $0.9 billion in our gas distribution system and $1.7 billion in our electric distribution over an initial five year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. This matter is pending. The current estimated cost of the entire program, including the first five years of investments for which we sought approval in this petition, is $3.9 billion. We anticipate seeking BPU approval to complete our investment under the program at a later date.

The estimated project expenditures related to this filing are not included above in our $7.1 billion three-year capital forecast table.

Disclosures about Long-Term Maturities, Contractual and Commercial Obligations and Certain Investments

The following table reflects our contractual cash obligations and other commercial commitments in the respective periods in which they are due. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 14. Schedule of Consolidated Debt. The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information.

Table of Contents

	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					
Power	$2,553	$44	$853	$250	$1,406
PSE&G	5,579	500	471	750	3,858
Transition Funding (PSE&G)	476	225	251	—	—
Transition Funding II (PSE&G)	20	12	8	—	—
Long-Term Non-Recourse Project Financing					
Other	16	—	16	—	—
Interest on Recourse Debt					
Power	1,214	132	245	182	655
PSE&G	3,850	232	417	387	2,814
Transition Funding (PSE&G)	38	27	11	—	—
Transition Funding II (PSE&G)	1	1	—	—	—
Interest on Non-Recourse Project Financing					
Other	2	1	1	—	—
Capital Lease Obligations					
Power	7	2	2	1	2
Services	13	7	6	—	—
Operating Leases					
Power	22	1	2	3	16
PSE&G	64	9	13	9	33
Services	214	—	15	26	173
Other	6	2	3	1	—
Energy-Related Purchase Commitments					
Power	3,364	661	1,227	701	775
Total Contractual Cash Obligations	$17,439	$1,856	$3,541	$2,310	$9,732
Commercial Commitments					
Standby Letters of Credit					
PSEG	$8	$8	$—	$—	$—
Power	$215	$215	$—	$—	$—
PSE&G	$13	$13	$—	$—	$—
Guarantees and Equity Commitments					
Power	10	9	—	—	1
Total Commercial Commitments	$246	$245	$—	$—	$1
Liability Payments for Uncertain Tax Positions					
PSEG	$2	$2	$—	$—	$—
Power	71	71	—	—	—
PSE&G	11	11	—	—	—
Other	73	73	—	—	—

Table of Contents

OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy contracts. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for further discussion.

Other

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

In the event that collection of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, the accounting treatment for some of the leases may change. In such cases, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would reclassify the lease from a leveraged lease to an operating lease and would consider the need to record an impairment of its investment. Should this event occur, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The market-related value of plan assets held
for the qualified pension and OPEB plans 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	2013		2012		2011	
Discount Rate	5.00	%	4.20	%	5.00	%
Rate of Return on Plan Assets	8.00	%	8.00	%	8.50	%

The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate used to determine year-end obligations is also used to develop the following year's net periodic pension cost.

In selecting the annual discount rate to calculate benefit obligations, we utilize a hypothetical portfolio of high quality corporate bonds with cash flows that match the benefit plan liability. The composite yield on the hypothetical bond portfolio reflects the rate at which the obligations could effectively be settled.

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 and long-term inflation assumptions.
Based on the above assumptions, we have estimated net periodic pension income of approximately $13 million, net of amounts capitalized, and no contributions in 2014.

Table of Contents

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 eight years.

Effect if Different Assumptions Used: As part of the business planning process, we have modeled future costs assuming an 8.00% rate of return and a 5.00% discount rate for 2014, increasing annually by 25 basis points to 5.75% in 2017 and beyond. 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, 2013	Increase to Pension Expense in 2014
		Millions	
Discount Rate	(1)%	$644	$69
Rate of Return on Plan Assets	(1)%	$—	$50

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

Hedge and MTM Accounting

Current guidance requires us to recognize the fair value of derivative instruments, not designated as normal purchases or normal sales, at their fair value on the balance sheet. Many non-trading contracts qualify for normal purchases and normal sales exemption and are accounted for upon settlement.

Assumptions and Approach Used: In general, the fair value of our derivative instruments is determined by reference to quoted market prices from contracts listed on exchanges or from brokers. Some of these derivative contracts are long-term and rely on forward price quotations over the entire duration of the derivative contracts.

For a small number of contracts where quoted market prices are not available, we utilize mathematical models that rely on historical data to develop forward pricing information in the determination of fair value. Because the determination of fair value using such models is subject to significant assumptions and estimates, we developed reserve policies that are consistently applied to model-generated results to determine reasonable estimates of the fair value to record in the financial statements.

We have entered into various derivative instruments to manage risk from changes in commodity prices and interest rates. In accordance with our hedging strategy, derivatives that are hedging these risks and qualify are designated as either cash flow hedges or fair value hedges. For derivatives designated as hedges, the change in the value of a derivative instrument is measured against the offsetting change in the value of the underlying contract, anticipated transaction or other business condition that the derivative instrument is intended to hedge. This is known as the measure of hedge effectiveness. Changes in the fair value of the effective portion of a derivative instrument designated as a fair value hedge, along with changes in the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of the effective portion of derivative instruments designated as cash flow hedges, are reported in Accumulated Other Comprehensive Income (Loss), net of tax, until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Income (Loss).

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 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.

Table of Contents

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data—Note 16. Financial Risk Management Activities.

Lease Investments

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

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

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

Residual valuations are performed annually for each plant subject to lease using specific assumptions tailored to each plant. Those annual 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, or a change in the credit rating or bankruptcy of a counterparty, 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 $179 million.

NDT Fund

Our NDT Fund is comprised of both debt and equity securities. The assets in the NDT Fund are classified as available-for-sale securities and are marked to market with unrealized gains and losses recorded in Accumulated Other Comprehensive Income (Loss) unless securities with such unrealized losses are deemed to be other-than-temporarily impaired. Realized gains, losses and dividend and interest income are recorded in our Consolidated Statements of Operations as Other Income and Other Deductions. Unrealized losses that are deemed to be other-than-temporarily impaired are charged against earnings rather than Accumulated Other Comprehensive Income (Loss) and reflected as a separate line in the Consolidated Statement of Operations.

Assumptions and Approach Used: The NDT Fund investments are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. See Item 8. Financial Statements and Supplementary Data—Note 17. Fair Value Measurements for additional information.

Effect if Different Assumptions Used: Any significant changes to the fair market values of the fund securities could result in a material change in the value of our NDT Fund with a corresponding impact to earnings, which could potentially result in additional funding requirements to satisfy our decommissioning obligations. See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.

Asset Retirement Obligations (ARO)

Power, PSE&G 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 ratemaking process. We accrete the ARO liability to reflect the passage of time.

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

Table of Contents

- estimation of dates for retirement,
- 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 every three years unless new information necessitates more frequent updates. The most recent cost study was done in 2012. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power’s nuclear facilities comprised 92% of Power’s total AROs as of December 31, 2013. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

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

Effect if Different Assumptions Used: Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a 1% decrease in the discount rate would result in a $137 million increase in the Nuclear ARO as of December 31, 2013. A 1% increase in the inflation rate would result in a $353 million increase in the Nuclear ARO as of December 31, 2013. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $289 million at December 31, 2013.

Accounting for Regulated Businesses

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

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

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

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

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

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

Accounting for Insurance Proceeds

In late October 2012, strong winds and the resulting storm surge from Superstorm Sandy caused severe damage to our transmission and distribution system throughout our service territory as well as to some of our generation infrastructure. PSE&G has recognized $6 million in insurance proceeds. Power received total insurance proceeds of $44 million related to their expenses. See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities for additional information.

Assumptions and Approach Used: As of December 31, 2013, we recovered approximately $50 million in total from our insurance carriers. In June 2013, PSEG, Power and PSE&G filed suit in New Jersey state court against the insurance carriers seeking legal interpretation of certain terms in the insurance policies regarding losses from damage caused by Superstorm Sandy's storm surge. In August 2013, the insurance carriers filed an answer in which they denied most of the allegations made in the complaint. Discovery is ongoing. We believe that any further proceeds to be received under our policies are not estimable at December 31, 2013.

Effect if Different Assumptions Used: If we were to use different assumptions regarding additional insurance proceeds, there would be a dollar for dollar effect on Operation and Maintenance Expense and Operating Income for Power. If we were to recognize any additional insurance proceeds for PSE&G, we would allocate those proceeds between Operation and Maintenance Expense and costs that have been deferred for regulatory recovery or capitalized. In either case, we would not recognize insurance proceeds in excess of actual costs incurred.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Commodity Contracts

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

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses. MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

Table of Contents

	MTM VaR Millions	
Years Ended December 31,	2013	2012
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$12	$18
Average for the Period	$15	$16
High	$29	$29
Low	$8	$7
99.5% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$18	$28
Average for the Period	$23	$25
High	$46	$46
Low	$13	$11

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

Interest Rates

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

As of December 31, 2013, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $288 million decrease in the fair value of debt, including a $68 million decrease at Power and a $220 million decrease at PSE&G.

Debt and Equity Securities

We have $5.4 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,
- 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 of both fixed income and equity securities totaling $1.7 billion as of December 31, 2013. As of December 31, 2013, the portfolio includes $897 million of equity securities and $720 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, 2013, 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 duration of 5.55 years and a yield of 2.48%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2013, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $40 million.

64

Table of Contents

Credit Risk

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

BGS suppliers expose PSE&G to credit losses in the event of non-performance or non-payment upon a default of the BGS supplier. Credit requirements are governed under BPU-approved BGS contracts.

Energy Holdings has credit risk related to its investments in leases, which totaled $98 million, net of deferred taxes of $727 million, as of December 31, 2013. These leveraged leases are concentrated in the United States energy industry. See Item 8. Financial Statements and Supplementary Data – Note 8. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets. In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment, including deferred taxes, in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings' portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations as to any other company.

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
Public Service Enterprise Group Incorporated:

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(a). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2014

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Member and Board of Directors of
PSEG Power LLC:

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, member's equity, and cash flows for each of the three years in the period ended December 31, 2013. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2014

Table of Contents

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

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2013 and 2012, 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, 2013. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 26, 2014

Table of Contents

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

	Years Ended December 31, 2013	2012	2011
OPERATING REVENUES	$9,968	$9,781	$11,079
OPERATING EXPENSES			
Energy Costs	3,536	3,719	4,747
Operation and Maintenance	2,887	2,632	2,481
Depreciation and Amortization	1,178	1,054	976
Taxes Other Than Income Taxes	68	98	133
Total Operating Expenses	7,669	7,503	8,337
OPERATING INCOME	2,299	2,278	2,742
Income from Equity Method Investments	11	12	4
Other Income	213	260	220
Other Deductions	(54)	(98)	(85)
Other-Than-Temporary Impairments	(12)	(18)	(22)
Interest Expense	(402)	(423)	(475)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,055	2,011	2,384
Income Tax (Expense) Benefit	(812)	(736)	(977)
INCOME FROM CONTINUING OPERATIONS	1,243	1,275	1,407
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $0, $0 and $(51) for the years ended 2013, 2012 and 2011, respectively	—	—	96
NET INCOME	$1,243	$1,275	$1,503
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):			
BASIC	505,889	505,933	505,949
DILUTED	507,525	507,086	506,982
EARNINGS PER SHARE:			
BASIC			
INCOME FROM CONTINUING OPERATIONS	$2.46	$2.52	$2.78
NET INCOME	$2.46	$2.52	$2.97
DILUTED			
INCOME FROM CONTINUING OPERATIONS	$2.45	$2.51	$2.77
NET INCOME	$2.45	$2.51	$2.96

See Notes to Consolidated Financial Statements.

Table of Contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2013	2012	2011
NET INCOME	$1,243	$1,275	$1,503
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(54), $(24) and $43 for the years ended 2013, 2012 and 2011, respectively	55	19	(39)
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7, $18 and $54 for the years ended 2013, 2012 and 2011, respectively	(9)	(24)	(80)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(172), $32 and $44 for the years ended 2013, 2012 and 2011, respectively	247	(46)	(62)
Other Comprehensive Income (Loss), net of tax	293	(51)	(181)
COMPREHENSIVE INCOME	$1,536	$1,224	$1,322

See Notes to Consolidated Financial Statements.

Table of Contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2013	2012
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$493	$379
Accounts Receivable, net of allowances of $56 and $56 in 2013 and 2012, respectively	1,203	1,069
Tax Receivable	109	227
Unbilled Revenues	300	314
Fuel	545	583
Materials and Supplies, net	479	422
Prepayments	89	283
Derivative Contracts	98	138
Deferred Income Taxes	24	49
Regulatory Assets	243	349
Other	31	56
Total Current Assets	3,614	3,869
PROPERTY, PLANT AND EQUIPMENT	29,713	27,402
Less: Accumulated Depreciation and Amortization	(8,068)	(7,666)
Net Property, Plant and Equipment	21,645	19,736
NONCURRENT ASSETS		
Regulatory Assets	2,612	3,830
Regulatory Assets of Variable Interest Entities (VIEs)	476	713
Long-Term Investments	1,313	1,324
Nuclear Decommissioning Trust (NDT) Fund	1,701	1,540
Other Special Funds	613	191
Goodwill	16	16
Other Intangibles	33	34
Derivative Contracts	163	153
Restricted Cash of VIEs	24	23
Other	312	296
Total Noncurrent Assets	7,263	8,120
TOTAL ASSETS	$32,522	$31,725

See Notes to Consolidated Financial Statements.

Table of Contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2013	2012
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$544	$1,026
Securitization Debt of VIEs Due Within One Year	237	226
Commercial Paper and Loans	60	263
Accounts Payable	1,222	1,304
Derivative Contracts	76	46
Accrued Interest	95	91
Accrued Taxes	37	17
Deferred Income Taxes	—	72
Clean Energy Program	142	153
Obligation to Return Cash Collateral	119	122
Regulatory Liabilities	43	67
Other	488	390
Total Current Liabilities	3,063	3,777
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	7,107	6,542
Regulatory Liabilities	233	209
Regulatory Liabilities of VIEs	11	10
Asset Retirement Obligations	677	627
Other Postretirement Benefit (OPEB) Costs	1,095	1,285
Accrued Pension Costs	121	876
Environmental Costs	414	537
Derivative Contracts	31	122
Long-Term Accrued Taxes	180	164
Other	119	108
Total Noncurrent Liabilities	9,988	10,480
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	7,587	6,148
Securitization Debt of VIEs	259	496
Project Level, Non-Recourse Debt	16	43
Total Long-Term Debt	7,862	6,687
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2013 and 2012— 533,556,660 shares	4,861	4,833
Treasury Stock, at cost, 2013— 27,699,398 shares; 2012— 27,664,188 shares	(615)	(607)
Retained Earnings	7,457	6,942
Accumulated Other Comprehensive Loss	(95)	(388)
Total Common Stockholders' Equity	11,608	10,780
Noncontrolling Interest	1	1

Total Stockholders' Equity	11,609	10,781
Total Capitalization	19,471	17,468
TOTAL LIABILITIES AND CAPITALIZATION	$32,522	$31,725

See Notes to Consolidated Financial Statements.

Table of Contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2013	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$1,243	$1,275	$1,503
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	—	—	(122)
Depreciation and Amortization	1,178	1,054	982
Amortization of Nuclear Fuel	192	173	153
Provision for Deferred Income Taxes (Other than Leases) and ITC	270	721	811
Non-Cash Employee Benefit Plan Costs	243	271	175
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	31	93	(55)
Loss on Leases, net of tax	—	—	170
Net (Gain) Loss on Lease Investments	2	(49)	(55)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	79	63	(165)
Change in Accrued Storm Costs	(90)	(90)	(60)
Net Change in Regulatory Assets and Liabilities	2	(132)	(130)
Cost of Removal	(93)	(116)	(62)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(104)	(118)	(117)
Net Change in Tax Receivable	19	(211)	673
Net Change in Certain Current Assets and Liabilities	299	97	247
Employee Benefit Plan Funding and Related Payments	(231)	(314)	(508)
Other	118	70	117
Net Cash Provided By (Used In) Operating Activities	3,158	2,787	3,557
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,811)	(2,574)	(2,083)
Proceeds from Sale of Discontinued Operations	—	—	687
Proceeds from Sale of Capital Leases and Investments	50	58	179
Proceeds from Sales of Available-for-Sale Securities	1,159	1,666	1,355
Investments in Available-for-Sale Securities	(1,170)	(1,700)	(1,386)
Other	(29)	(75)	(21)
Net Cash Provided By (Used In) Investing Activities	(2,801)	(2,625)	(1,269)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	(203)	263	(64)
Issuance of Long-Term Debt	2,000	900	794
Redemption of Long-Term Debt	(1,025)	(787)	(1,514)
Redemption of Securitization Debt	(226)	(216)	(206)
Repayment of Non-Recourse Debt	—	(1)	(1)
Cash Dividend Paid on Common Stock	(728)	(718)	(693)
Other	(61)	(58)	(50)
Net Cash Provided By (Used In) Financing Activities	(243)	(617)	(1,734)
Net Increase (Decrease) in Cash and Cash Equivalents	114	(455)	554
Cash and Cash Equivalents at Beginning of Period	379	834	280
Cash and Cash Equivalents at End of Period	$493	$379	$834

Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$241	$121	&#1