PUBLIC SERVICE ELECTRIC & GAS CO
Form 10-K
February 26, 2013
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
100 F ST., N.E.
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, 2012,
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
	First and Refunding Mortgage Bonds	
Public Service Electric and Gas Company	9 1/4% Series CC, due 2021 6 3/4% Series VV, due 2016 8%, due 2037	New York Stock Exchange

5%, due 2037

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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 is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

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

Public Service Enterprise Group Incorporated	Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨
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, 2012 was $16,420,936,616 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, 2013 was 505,959,216.

As of January 31, 2013, 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 2013 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 8, 2013, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report 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,” “forecas variations of such words and similar expressions are intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in 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). 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,
- increase in competition in energy supply markets as well as competition for certain rate-based 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 and customer usage patterns.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or, even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations.

Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

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

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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, PSE&G and PSEG Energy Holdings L.L.C. (Energy Holdings). Depending on the context of each section, references to “we,” “us,” and “our” relate to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 191.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and special 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 three direct wholly owned subsidiaries, Power, PSE&G and Energy Holdings, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. PSEG Services Corporation (Services), our other wholly owned subsidiary, provides us and these operating subsidiaries with certain management, administrative and general services at cost.

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 direct operating subsidiaries.

Power	PSE&G	Energy Holdings
A Delaware limited liability company formed in 1999 that integrates its generating asset operations with its wholesale energy sales, fuel supply and energy trading functions.	A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory.	A New Jersey limited liability company (successor to a corporation which was formed in 1989) that invests and operates through its two primary subsidiaries.
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.	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	Earns revenues primarily from its portfolio of lease investments and its solar generation projects.

customers throughout its service territory.

Has also implemented demand response and energy efficiency programs and invested in solar generation within New Jersey.

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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 and oil-fired generation facilities, while balancing generation production, fuel requirements and supply obligations through energy portfolio management. We use commodity contracts and financial instruments, combined with our owned generation, 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 spot 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 if 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, 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 contract was for an initial period which extended through March 31, 2012 and continues on a year-to-year basis thereafter, 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 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 availability, Power also sells gas to others.

How Power Operates

We own approximately 13,226 MW of generation capacity located in the Northeast and Mid-Atlantic regions of the United States in some of the country’s largest and most developed electricity markets.

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

• Generation Capacity

Power has approved the expenditure of approximately $192 million for a steam path retrofit and related upgrades at its co-owned Peach Bottom Units 2 and 3. Unit 3 upgrades were completed in October 2011. Unit 2 upgrades were completed in October 2012. The balance of work to ensure efficient operation is expected to be completed by 2014. Total expenditures through December 31, 2012 were $154 million.

Power has also 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 by 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, 2012 were $73 million.

In 2011, we sold 2,000 MW of generation facilities we owned and operated in Texas. See Item 8. Financial Statements and Supplementary Data—Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies and Note 4. Discontinued Operations and Dispositions, for additional information.

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

Our installed capacity utilizes a diverse mix of fuels: 45% gas, 28% nuclear, 18% coal, 8% 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 2012 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.

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Generation by Fuel Type	Actual 2012	
Nuclear:		
New Jersey facilities	39	%
Pennsylvania facilities	18	%
Fossil:		
Coal:		
Pennsylvania facilities	9	%
Connecticut facilities	—	%(A)
Coal and Natural Gas:		
New Jersey facilities	2	%
Oil and Natural Gas:		
New Jersey facilities	23	%
New York facilities	9	%
Connecticut facilities	—	%(A)
Total	100	%

(A) 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 2012, our base load capacity factors were as follows:

Unit	2012 Capacity Factor	
Nuclear		
Salem Unit 1	95.2	%
Salem Unit 2	87.3	%
Hope Creek	89.8	%
Peach Bottom Unit 2	85.9	%
Peach Bottom Unit 3	99.0	%
Coal		
Keystone	63.8	%
Conemaugh	71.3	%

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 lower efficiency and/or the use of higher-cost fuels such as oil, natural gas and, in some cases, coal. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.

- Peaking Units run the least amount of time and 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. The majority of

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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 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. 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 merit order of dispatch of our units in PJM Interconnection L.L.C. (PJM), 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 generation to displace some coal generation.

The size of each facility's fuel circle in the above chart illustrates the relative MW capacity of the 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 an environment in the markets such that natural gas prices often have a major impact 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.

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Historical data and forward prices would 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 tables 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, 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—To run our nuclear units we have long-term contracts for nuclear fuel. These contracts provide for:
  - purchase of uranium (concentrates and uranium hexafluoride),
  - conversion of uranium concentrates to uranium hexafluoride,
  - enrichment of uranium hexafluoride, and
  - fabrication of nuclear fuel assemblies.

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- Coal Supply—Coal is the primary fuel for our Keystone, Conemaugh and Bridgeport stations. Coal is also used by Hudson and Mercer which 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 minimize 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 our Bridgeport 3 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 four interstate pipelines with whom we have contracted. In addition, we have firm gas transportation contracts to serve our Bethlehem Energy Center (BEC) 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. On an as available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet. We supplement that supply with a total storage capacity of 76 billion cubic feet.

- 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 2012 and Future Outlook and Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities.

Markets and Market Pricing

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 60 million people, nearly 20% of the total United States population, and has a peak demand of over 163,848 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 NYISO is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 19 million and a peak demand of over 33,939 MW. Our BEC station operates in New York.
- New England—ISO-NE coordinates the movement of electricity in a region covering Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 14 million and a peak demand of over 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 produce these products, 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 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 electricity prices. One of the reasons for the decline in natural gas prices is greater supply from shale production. This trend has reduced margin on forward sales as we re-contract our expected generation output.

In addition to energy sales, we also earn revenue from capacity payments for our generating assets. These payments are compensation for committing a portion of our capacity to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there is 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, raising concerns about reliability and creating 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, resulting in an improved 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. The majority of our PJM generating units are located in zones where the following prices have been set:

Delivery Year	MW-day	kW-yr
June 2012 to May 2013	$139.73	$51.70
June 2013 to May 2014	$245.00	$89.43
June 2014 to May 2015	$136.50	$49.82
June 2015 to May 2016	$167.46	$61.12

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.

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.

On a prospective basis, many factors may affect the capacity pricing, 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 outages, etc.),
- increases in transmission capability between zones,
- changes to the pricing mechanism, 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
- changes driven by legislative and/or regulatory action, 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.

Hedging Strategy

In an attempt 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:

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Load Zone ($/MWh)	2009-2012	2010-2013	2011-2014	2012-2015	2013-2016
PSE&G	$103.72	$95.77	$94.30	$83.88	$92.18
Jersey Central Power & Light	$103.51	$95.17	$92.56	$81.76	$83.70
Atlantic City Electric	$105.36	$98.56	$100.95	$85.10	$87.27
Rockland Electric Company	$112.70	$103.32	$106.84	$92.51	$92.58

We have obtained price certainty for all of our PJM and New England capacity through May 2016 through the RPM and FCM pricing mechanisms.

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 all 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 by third party suppliers. 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.

Historically, the number of customers that have switched to third party suppliers was relatively constant, but in recent years, as market prices declined from past years' historic highs, there was additional incentive for more of the smaller commercial and industrial electric customers to switch. 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. While this impact has been reduced as average BGS rates have declined to a level more closely resembling current market prices, customers may still see 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.

As of February 6, 2013, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2015.

Base Load Generation	2013	2014	2015
Generation Sales	100%	80%-85%	40%-45%

Our 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 its estimated uranium, enrichment and fabrication requirements for the three years. 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 its 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.

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.

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PSE&G

Our 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.

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

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

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

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information concerning these programs and the components of our tariffs, see Regulatory Issues.

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How PSE&G Operates

We provide network transmission and point-to-point transmission services, which are coordinated with PJM, and 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 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 on current transmission construction activities, see Regulatory Issues, Federal Regulation—Transmission Regulation.

Transmission Statistics

December 31, 2012		
Network Circuit Miles	Billing Peak (MW)	Historical Annual Load Growth 2008-2012
1,461	10,470	0.4%

Distribution

The primary business of our utility is the distribution of gas and electricity to end users in our service territory. Our load requirements were split among residential, commercial and industrial customers, as described below for 2012. We believe that we have all the franchise rights (including consents) necessary for our electric and gas distribution operations in the territory we serve.

	% of 2012 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 and electric load have declined as illustrated:

Electric and Gas Distribution Statistics

	December 31, 2012				
	Number of Customers		Electric Sales and Gas Sold and Transported		Historical Annual Load Decline 2008-2012
Electric	2.2	Million	41,641	GWh	(1.4)%
Gas	1.8	Million	3,397	Million Therms	(0.6)%

The decline in both electric and gas sales were impacted by the unfavorable winter weather experienced in 2012 and customer conservation as a result of the economy. The first six months of 2012 were the warmest first half of a year on record in the United States. Electric sales were also impacted by a decline in the Industrial sector.

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Solar Generation

We have undertaken major initiatives in order to spur investment in solar power in New Jersey. For additional details, please refer to our discussion under Energy Policy.

Supply

Although commodity revenues make up almost 48% of our revenues, we make no margin on the supply of energy 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 electric and gas customers within our service territory that are not served by another supplier. As a practical matter, this means we are obligated to provide supply to a vast majority of residential customers and a smaller portion of commercial and industrial customers.

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.

PSE&G procures the supply requirements of our 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. 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 2012 and Future Outlook.

Energy Holdings

Energy Holdings primarily owns and manages a portfolio of lease investments and solar generation projects and is exploring opportunities for additional investment in renewable generation.

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. In February, 2012, the California Public Utilities Commission approved the shutdown of GWF Power and we anticipate recovering the remaining book value of our investment. For additional information on these generation facilities, see Item 2. Properties.

Products and Services

The majority of our remaining $840 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2012, 67% of our total leveraged lease investments were rated as below investment grade by Standard & Poor's.

Our 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.

Through Energy Holdings, we own and operate solar projects in New Jersey, Delaware, Florida, Ohio and Arizona totaling 69 MW. See Item 2. Properties for additional information.

In January 2012, we acquired a 25 MW solar project in Arizona. This project is currently in service. All of the energy, capacity and environmental attributes generated by the project in the first 20 years are expected to be sold under a long-term power purchase agreement. The total investment for the project was approximately $75 million.

In September 2012, we acquired a 15 MW solar project in Delaware. This project is currently in service. The project has a 20-year power purchase agreement for energy and the majority of renewable energy credits with a wholesale electric utility servicing municipal EDCs in Delaware. Energy Holdings has issued guarantees of up to $37 million for payment of obligations related to the construction of the project, of which $4 million was outstanding as of December 31, 2012. The total investment for the project was approximately $47 million.

In December 2012, we acquired an additional 19 MW solar project currently under construction in Arizona. The project is expected to begin commercial operation in the latter half of 2013. Energy Holdings has issued guarantees of up to $48 million for payment of obligations related to the construction of the project, all of which were outstanding as of December 31, 2012. The total investment for the project is expected to be approximately $51 million.

Also, in December 2011, the Long Island Power Authority (LIPA) selected PSEG Long Island LLC (PSEG LI), a newly formed wholly owned subsidiary of Energy Holdings, to manage its electric transmission and distribution system in Long Island, New York. LIPA issued a press release that it had selected us for a variety of reasons, including our proven track record of first quartile customer service and reliability, commitment to cost control, corporate culture of transparency and local decision making, technical expertise and proven environmental track record. The ten-year contract, Operations Services Agreement (OSA), is scheduled to commence on January 1, 2014, following completion of the Transition Services Agreement (TSA). As part of the OSA, PSEG LI will be expected to develop and manage the implementation of a number of operational improvements to provide safe and reliable service for LIPA’s customers, increase customer satisfaction and manage the operational and maintenance costs of LIPA. In November, 2012, the Governor of New York initiated an inquiry into the current structure of LIPA as a political subdivision of the State Of New York. The privatization of LIPA's transmission and distribution system is among the restructuring options under consideration. LIPA has the right under the OSA and the TSA to terminate each agreement, in the event that LIPA elects to either transfer its transmission and distribution system to a third party (privatization) or operate and maintain its transmission and distribution system with its own employees (municipalization). If LIPA elects to implement either of these options, LIPA is required to pay PSEG LI its service fees, milestone payments and wind-down expenses, in each case up to the effective date of such termination.

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, customer migration and other factors. It is also possible that advances in technology, such as distributed generation, 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 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.

We are also at risk if the states in which we operate take actions that interfere with competitive wholesale markets. For example, on January 28, 2011, New Jersey enacted a law establishing a long-term capacity agreement pilot program (LCAPP) which provides for up to 2,000 MW of subsidized base load or mid-merit electric power generation. This action may have the effect of artificially depressing prices in the competitive wholesale market and thus has 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, 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. 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 additional competition to build transmission lines in our area in the future and would allow us to seek opportunities to build in other service territories.

Construction of new local generation, such as the proposed subsidized generation in New Jersey and Maryland, 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, 2012, we had 9,798 employees within our subsidiaries, including 6,248 covered under collective bargaining agreements. During the fourth quarter of 2012, we reached agreements with four labor unions to extend their collective bargaining agreements for four years. Three of these agreements expire in April 2017 and one expires in October 2017. Collectively, these four unions represent approximately 80% of union employees of PSE&G, Power and Services. Our collective bargaining agreements with our other two unions are set to expire in April and May 2014, respectively. We believe we maintain satisfactory relationships with our employees.

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Employees as of December 31, 2012

	Power	PSE&G	Energy Holdings	Services
Non-Union	1,172	1,398	15	965
Union	1,442	4,797	—	9
Total Employees	2,614	6,195	15	974
Number of Union Groups	3	5	—	1

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 Energy Holdings. 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 the FERC regulation fall into five general categories:

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

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 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 and PSEG Nuclear LLC were each granted continued MBR authority from the FERC in June 2011. PSEG New Haven LLC was also granted initial MBR authority in May 2012. Retention of MBR authority is important to the maintenance of our current generation business' revenues.

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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, NYISO, and ISO-NE each have capacity markets that have been approved by FERC.

PJM—RPM is a 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, and there is currently significant discussion about 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 should be measured and verified to ensure their availability.

ISO-NE—ISO-NE’s market for installed capacity with all generators in New England provides fixed capacity payments. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of generators on the system and contains incentive mechanisms to encourage generator availability during generation shortages. As in PJM, capacity market rules in ISO-NE continue to develop. We challenged in court the results of ISO-NE’s first forward capacity auction, arguing that our units received inadequate compensation notwithstanding the location of our resources in a constrained area. The D.C. Circuit Court of Appeals ruled in our favor and remanded the proceeding to the FERC where it remains pending. We and other generators also filed a complaint at the FERC regarding ISO-NE’s capacity market design, alleging that it insufficiently reflects locational capacity values. The FERC acted on the complaint, largely accepting the ISO-NE’s capacity market design; however, an appeal of this rule is pending.

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 recognizes only two separate zones that potentially may separate in price: New York City and Long Island. NYISO is creating a third locality encompassing the lower Hudson Valley to take effect May 1, 2014. The exact configuration of this new zone has not yet been determined. The triennial process for updating demand curves used for establishing capacity prices is also underway. The NYISO is required to file with the FERC by the end of 2013 revised demand curves covering the May 1, 2014 through April 30, 2017 period. Discussions 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 concluded that new natural gas-fired generation was needed and enacted the LCAPP Act to subsidize approximately 2,000 MW of new generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey Electric Distribution Companies (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 the SOCAs as directed by the State, but did so under protest reserving their rights. In May 2012, two of the three generators, CPV Shore, LLC (CPV), a subsidiary of Competitive Power Ventures, Inc. and Hess Newark, LLC (Hess), a subsidiary of Hess Corporation, that received SOCA contracts cleared the RPM auction for the 2015/2016 delivery year in the aggregate notional amount of approximately 1,300 MW of installed capacity.

Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and the appeal remains pending. In addition, the LCAPP Act has been challenged on constitutional grounds in federal court. The hearing for this matter is scheduled to begin in March 2013.

Maryland is also taking action to subsidize above-market new generation. In April 2012, the Maryland Public Service Commission (PSC) issued an order requiring the Maryland utility companies to enter into a contract with CPV Shore, LLC (CPV) to build a new 661 MW natural gas-fired, combined cycle station in Maryland with an in-service date of June 2015. This contract has not yet been finalized, as the Maryland PSC continues to evaluate its terms. In the May 2012 RPM auction, the CPV generator cleared the auction. We have joined other generators in challenging this order on constitutional grounds in federal court and that case is set for hearing in March 2013. The Maryland EDCs have also appealed the April 2012 order in state court.

These efforts to artificially depress prices in the wholesale capacity auction were intended to be mitigated by the Minimum Offer Price Rule (MOPR) approved by the FERC. The MOPR was intended to restrict new generation from bidding in RPM at less than an established minimum level established by Tariff, or a cost-based bid to the extent that the generator can demonstrate that its costs are lower than the MOPR. The MOPR was in place for the May 2012 auction, but we believe it did not operate to protect the market against these suppression efforts given that two of the three SOCA generators cleared the auction. As a result, discussions among a diverse group of PJM stakeholders to improve the MOPR ensued and a settlement was reached among those stakeholders. That proposal was then subject to a PJM stakeholder review and vote. The proposal was modified and received almost a 90% supporting vote. In December 2012, PJM filed Tariff changes with the FERC to implement the revised MOPR. In February 2013, the FERC issued a deficiency letter to PJM seeking additional information regarding the proposed MOPR changes. PJM must respond to those changes within 30 days and then the FERC has 60 days to act on the proposal. If FERC approves the proposal, we believe these modifications should significantly improve the MOPR rules and appropriately reduce the ability for subsidized generation assets to artificially suppress wholesale market prices. We cannot predict the outcome of this matter.

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/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. Our 2012 Annual Formula Rate Update with the FERC provided for approximately $94 million in increased annual transmission revenues effective January 1, 2012. We filed our 2013 Annual Formula Rate Update with the FERC in October 2012, which provides for approximately $174 million in increased annual transmission revenues effective January 1, 2013.

- Transmission Policy Developments—In 2010, the FERC initiated a proceeding to evaluate whether reforms to current transmission planning and cost allocation rules were necessary to stimulate additional transmission development. The rulemaking also addressed the issue of whether construction of transmission should be opened up to competition by eliminating the “right of first refusal” (ROFR) under which incumbent transmission companies such as PSE&G have a ROFR to build transmission located within their respective service territories. The FERC ultimately concluded in Order No. 1000 that the ROFR should be eliminated, subject to certain exceptions, and left it to Regional Transmission Organizations/Independent System Operators such as PJM to establish the implementation details. We, along with many other companies, have challenged the FERC's orders in federal court. In addition, we have joined other PJM transmission owners in filing for the FERC approval of new rules that will determine who pays for future transmission projects in PJM.

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 for certain types of transmission projects, while at the same time providing opportunities to build transmission outside of our service territory.

- Transmission Expansion—In June 2007, PJM identified the need for the construction of the Susquehanna-Roseland line, a new 500 kiloVolt (kV) transmission line intended to maintain the reliability of the electrical grid serving New Jersey customers. PJM assigned construction responsibility for the new line to us and PPL Corporation (PPL) for the New Jersey and Pennsylvania portions of the project, respectively. The estimated cost of our portion of this construction project is up to $790 million, and PJM had originally directed that the line be placed into service by June 2012. As of December 31, 2012, total capital expenditures were $324 million. Construction of the Susquehanna-Roseland line is contingent upon obtaining all necessary federal, state, municipal and landowner permits and approvals. We have obtained environmental permits for the project from the New Jersey Department of Environmental Protection (NJDEP). On October 1, 2012, the National Park Service (NPS) issued a final Environmental Impact Statement (EIS) for the Susquehanna-Roseland line, selecting our and PPL's choice of route in certain federal park lands subject to the NPS' jurisdiction that follows the existing right of way. On October 15, 2012, several environmental groups filed a complaint in federal court, which, as amended, challenges the NPS' issuance of the final EIS, seeking to set aside the EIS and asking the court for an injunction that would generally prohibit construction of the project within the federal park lands at issue. If this request for injunctive relief is granted, the construction schedule for the project could be impacted. We have begun construction in those areas where necessary permits have been obtained. Currently, the expected in-service date for the Eastern segment of the project is June 2014 and for the Western segment is June

2015, although further delays are possible. Delays in the construction schedule could impact the cost of construction and the timing of expected transmission revenues.

Also, in 2010, certain environmental groups had appealed the BPU's approval of the Susquehanna-Roseland line, although no stay was sought. On February 11, 2013, the Appellate Division of the New Jersey Superior Court issued an order rejecting the appeal and affirming the BPU's approval of the project.

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We had previously been directed by PJM to build a 500 kV reliability project from Branchburg to Roseland to Hudson. The scope of this project has since changed; it is now a 230 kV project referred to as the Northeast Grid project, for which we are currently seeking to obtain municipal siting approvals. The Northeast Grid project has an expected in-service date of June 2015 and an estimated cost of construction of $895 million. As of December 31, 2012, total capital expenditures were $88 million.

In 2012, both the BPU and the NJDEP approved siting of the North Central Reliability project. This project, which involves upgrading certain circuits and switching stations from 138 kV to 230 kV in the northern and central portions of New Jersey, is estimated to cost up to $390 million and has an in-service date of June 2014. The project is currently under construction and, as of December 31, 2012, total capital expenditures for this project were $163 million.

In 2012, we received both municipal siting and the NJDEP approval for the Burlington-Camden project. The project, which also involves upgrading certain circuits and switching stations from 138 kV to 230 kV in the southern portion of New Jersey, is estimated to cost up to $399 million and has an in-service date of June 2014. The project is currently under construction. As of December 31, 2012, total capital expenditures for the project were $169 million.

We are still in the process of obtaining necessary municipal and environmental approvals for the Mickleton-Gloucester-Camden project. This is another project that involves converting both circuits and switching stations from 138 kV to 230 kV in southern New Jersey and is estimated to cost up to $435 million. The project has an in-service date of June 2015. This project is still in the engineering/design phase and, as of December 31, 2012, total capital expenditures were $24 million.

- Transmission Rate Proceedings—In September 2011, the Massachusetts Attorney General, along with several state utility commissions, consumer advocates and consumer groups from six New England states, filed a complaint at the FERC against a group of New England transmission owners seeking to reduce the base return on equity used in calculating these transmission owners' formula transmission rates. The matter has been set for hearing, and the proceeding is pending. In addition, there have been FERC complaints filed by municipal utilities in New York against a New York transmission-owning utility seeking to lower that utility's transmission ROE. While we are not the subject of any of these complaints. The results of these proceedings could set a precedent for the FERC-regulated transmission owners with formula rates in place, such as ours.

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 economic 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. Our generation assets were audited in 2011 and our utility assets were audited in 2012. NERC compliance represents a significant and challenging area of compliance responsibility for us. As new standards are developed and approved, existing standards are revised and registration requirements are modified which could 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. For example, the CFTC has issued rules defining the term “swap dealer” and “commercial end user” (We fall in the latter category). The CFTC also issued rules establishing position limits for trading in certain commodities, such as natural gas but a federal court vacated these rules. The CFTC has appealed this decision to vacate the position limits rules. We are currently preparing to comply with the new record keeping and data reporting requirements of the Dodd-Frank Act applicable to commercial end users, for compliance in April 2013. We are continuing to analyze the potential impact of these rules and preparing to comply with the requirements that apply to entities that are considered commercial end-users under the Dodd-Frank Act.

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 below:

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

In 2010, we also filed an application for an Early Site Permit (ESP) for a new nuclear generating station to be located at the current site of the Salem and Hope Creek generating stations. The NRC acceptance review is complete and agency evaluation is underway. There were no petitions filed for permission to intervene. The current NRC schedule would likely result in a decision with respect to the issuance of the ESP in 2015. While the ESP qualifies the site as an approved location for a new reactor for a period of 20 years, it imposes no obligation to do so.
As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in March 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. Additional regulations are expected.
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
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. Our utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the BPU, as the terms and conditions of these

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

We are also subject to various other states' regulations due to our operations in those states.

Rates

- Electric and Gas Base Rates—We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate adjustment was in 2010.

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- Rate Adjustment Clauses and Other Regulatory Filings—In addition to base rates, we recover certain costs or earn on certain investments, from customers pursuant to mechanisms known as adjustment clauses. These clauses permit, at set intervals, 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.

Some of our more significant recovery mechanisms and filings are as follows:

- Storm Damage Deferral—In December 2012, the BPU granted our request to defer on our books actually incurred, uninsured, incremental storm restoration costs to our gas and electric distribution systems associated with extraordinary storms, including Hurricane Irene and Superstorm Sandy. In February 2013, the BPU announced that it would initiate a generic proceeding to evaluate the prudency of extraordinary, storm-related costs incurred by all of the regulated utilities as a result of the natural disasters experienced in New Jersey in 2011 and 2012 and in this proceeding will consider the manner in which such prudent costs shall be recovered.
- Capital Infrastructure Programs (CIP I and CIP II)—We have received approval from the BPU for programs that provide for accelerated investment in utility infrastructure. The goal of these accelerated capital investments is to improve the reliability of our utility's infrastructure and New Jersey's economy through job creation. The programs allow us to receive a full return of and on our investments. In December 2012, the BPU approved stipulations regarding our CIP I and CIP II filings effective January 1, 2013. These Orders resulted in a combined increase of $40 million and $23 million for electric and gas customers, respectively.
- Weather Normalization Clause (WNC)—Our WNC is an annual rate mechanism that allows us to increase our rates to compensate for lower revenues we receive from customers as a result of warmer-than-normal winters and to decrease our rates to make up for higher revenues we receive as a result of colder-than-normal winters. The payments and refunds are subject to certain limitations and rate caps. Unrecovered balances associated with application of the rate cap are deferred until the next recovery period. This rate mechanism requires us to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred. In June 2012, we filed a petition and testimony with the BPU including eight months of actual and four months of forecasted data, which sought BPU approval to recover $41 million in deficiency revenues from our customers during the 2012-2013 Winter Period (October 1 to May 31) and a carryover deficiency of $16 million to the 2013-2014 Winter Period. In September 2012, an Order approving the stipulation for provisional rates was signed. In December 2012, we made a supplemental filing incorporating twelve months of actual financial data, which would, if approved by the BPU, result in no change to customer rates during the 2012-2013 Winter Period. The supplemental filing would, however, result in an increase of the carryover deficiency to the 2013-2014 Winter Period from $16 million to $24 million. We are awaiting a final Order.
- Solar and Energy Efficiency Recovery Charges (RRC)—are comprised of: Carbon Abatement, Energy Efficiency Economic Stimulus Program (EEE), EEE Extension, Demand Response, Solar 4 All, and Solar Loan II. These programs are aimed at reducing the New Jersey's Greenhouse Gas (GHG) Emissions. We file for annual recovery for our investments under these programs which includes a return on our investment and recovery of expenses. In July 2012, we filed a petition with the BPU requesting an increase in RRC seeking to recover approximately $62 million in electric revenue and $8 million in gas revenue, on an annual basis consistent with the terms of the approved program. The discovery phase of this proceeding is underway.

Other material rate filings pending before the BPU include:

Energy Strong (ES) 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 harden and 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. For additional information, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements.

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Solar 4 All Extension—In July 2012, we filed for an extension of our Solar 4 All program. In this filing, we are seeking BPU approval to invest up to $690 million to develop 136 MW of utility-owned solar photovoltaic systems over a five year period starting in 2013. Consistent with the existing Solar 4 All program, we propose to sell the energy and capacity from the solar systems in the PJM wholesale energy and capacity markets which will offset the cost of the program.

We also filed for an additional extension of our Solar Loan program (Solar Loan III) in July 2012. In the filing, we are seeking BPU approval to provide financing support for the installation of 97.5 MW of solar systems by providing loans to qualified customers. The total investment of the proposed Solar Loan III program is anticipated to be up to $193 million once the program is fully subscribed, the projects are built and the loans are closed.

Energy Supply

BGS—New Jersey's EDCs provide two types of BGS, the default electric supply service for customers who do not have a third party 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).

All of New Jersey's EDCs jointly procure the supply to meet their BGS obligations through two concurrent auctions authorized each year 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 provide BGS to New Jersey's EDCs.

Approximately one-third of PSE&G's total BGS-Fixed Price eligible load is auctioned each year for a three-year term. Current pricing is as follows:

	2010	2011	2012	2013	
36 Month Terms Ending	May 2013	May 2014	May 2015	May 2016	(A)
Eligible Load (MW)	2,800	2,800	2,900	2,800	
$ per kWh	0.09577	0.09430	0.08388	0.09218	

(A)Prices set in the February 2013 BGS Auction will be effective on June 1, 2013 when the 2010 BGS agreements expire.

The BPU approved the auction process for 2013 with no significant changes to the process.

For additional information, see Item 8. Financial Statements and Supplementary Data— Note 13. Commitments and Contingent Liabilities.

BGSS—BGSS is the mechanism approved by the BPU designed to recover all gas costs related to the supply for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of up to 5% and also may reduce the BGSS rate at any time.

PSE&G had a full requirements contract with Power for an initial period which extended through March 2012 to meet the supply requirements of default service gas customers. This long-term contract continues on a year-to-year basis thereafter, unless terminated by either party with a one year notice. Power charges PSE&G for gas commodity costs which PSE&G recovers from customers. Any difference between rates charged by Power under the BGSS contract and rates charged to PSE&G's residential customers are deferred and collected or refunded through adjustments in future rates. PSE&G earns no margin on the provision of BGSS.

In June 2012, we made our annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $71 million, excluding sales and use tax, to be effective October 1, 2012. This represented a reduction of approximately 5.2% for a typical residential gas heating customer. This BGSS reduction was the ninth consecutive reduction since January 2009. We entered into a Stipulation with the parties which put the requested lower BGSS rate into effect as filed on October 1, 2012 on a provisional basis. A final decision is expected in early 2013.

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Energy Policy

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. The most recent EMP was finalized in December 2011.

The 2011 EMP places an emphasis on expanding in-state electricity resources and reducing energy costs. The plan also recognizes the impact of climate change and accepts the previously set goal of a 22.5% target for the renewable portfolio standard (RPS) in 2021. It also references a goal that 70% of New Jersey's energy supplies should be from clean energy sources by 2050. To meet this goal, the plan redefined clean energy to include nuclear, natural gas and hydro power along with defined renewable sources and proposes a number of changes aimed at reducing the cost of achieving the 22.5% goal.

Specific program initiatives in the EMP include:

- construction of new combined cycle natural gas plants through the implementation of LCAPP, with the continued State challenge to FERC and PJM policies on market pricing rules in the capacity market,
- support for construction of new nuclear generation,
- changes to the solar program to reduce cost, expand opportunities, expand transparency and ensure economic and environmental benefits,
- expanded natural gas use to meet energy needs,
- development of decentralized combined heat and power,
- redesign of the delivery of state energy efficiency programs, and
- continued support for implementation of off-shore wind, without setting a specific capacity goal.

Solar Initiatives—In order to spur investment in solar power in New Jersey and meet renewable energy goals, we have undertaken two major initiatives at PSE&G.

- Solar Loans: The first solar initiative helps finance the installation of 81 MW of solar systems throughout our electric service area by providing loans to customers. The borrowers can repay the loans over a period of either 10 years (for residential customer loans) or 15 years (for non-residential customers), by providing us with solar renewable energy certificates (SRECs) or cash. The value of the SRECs towards the repayment of the loan is guaranteed to be not less than a floor price. SRECs received by us in repayment of the loan are sold through a periodic auction. Proceeds are used to offset program costs.

The total investment of both phases of the Solar Loan Program is expected to be between $210 million and $250 million once the program is fully subscribed, projects are built and loans are closed. As of December 31, 2012, we have provided a total of $209 million in loans for 878 projects representing 67 MW.

- Solar 4 All: The second solar initiative is the Solar 4 All Program under which we are investing approximately $456 million to develop 80 MW of utility-owned solar photovoltaic (PV) systems over four years. The program consists of centralized solar systems 500 kW or greater installed on PSE&G-owned property and third-party sites in our electric service territory (40 MW) and solar panels installed on distribution system poles (40 MW). We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell any SRECs received from the projects through the same auction used in the loan program. Proceeds from these sales are used to offset program costs.

As of December 31, 2012, we have installed and placed in service 35 MW on approximately 160,000 distribution poles with an investment of approximately $245 million, and 39 MW of centralized solar systems representing 23 projects with an investment of approximately $192 million.

BPU Storm Report — In 2011, the BPU commenced an investigation of all four New Jersey electric utilities, including PSE&G, to examine their preparations, performance and restoration efforts during Hurricane Irene and the October 2011 snow storm. Following the completion of a report by its consultant, the BPU issued an order in January 2013, ordering the utilities to take specific action to improve their preparedness and responses to major storms. There are 103 separate measures contained in the Order, with most of the measures requiring utility implementation by September 2013. We are evaluating the implications of this report.

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BPU Audits

Management/Affiliate Audit—In 2009, the BPU, in accordance with New Jersey statutes, initiated audits of PSE&G with respect to the effectiveness of its management and its compliance with rules governing PSE&G's interactions with its affiliated companies. In 2012, the BPU issued a report making a number of findings and recommendations, including the finding that no violations of either the state or federal affiliate rules were found. The BPU is expected to issue an order addressing the audit report's findings and recommendations, although timing is uncertain.

BPU Investigations

RRC/CIP—In January 2012, New Jersey's Rate Counsel requested that the BPU investigate certain allegations of wrong doing in PSE&G’s solar, EEE, and CIP programs raised by three former employees in a lawsuit. The BPU initiated an inquiry into these allegations and requested documentation from PSE&G. PSE&G has cooperated with the BPU and provided all requested information and documentation.

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,
- 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.

- New Jersey Nitrogen Oxide (NO_x) Regulation: 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. Retirement notifications for the combustion turbines, except for Salem Unit 3, have been filed with PJM. The Salem Unit 3 combustion turbine (38 MW) will be transitioning to an emergency generator. Evaluations are ongoing for the steam electric generation units.
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Connecticut NO_x Regulation—Under current Connecticut regulations, our Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NOx emission limitations that were incorporated into the facilities' operating permits. In 2010, we negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

- Hazardous Air Pollutants Regulation—In accordance with a ruling of the United States Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) are scheduled to go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the CAA. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. The Court of Appeals has split the litigation related to these matters into three cases, addressing separately the existing source NESHAP, new source NESHAP and the NSPS. These cases remain pending. The EPA has stayed implementation of the new source NESHAP rule pending its reconsideration. The EPA published the proposed reconsideration for the new source NESHAP and the NSPS in the Federal Register on November 30, 2012. The EPA expects to finalize the reconsideration of the new source NESHAP and the NSPS in March 2013.

The impact to our fossil generation fleet in New Jersey and Connecticut and our jointly-owned coal fired generating facilities in Pennsylvania is currently being determined. We believe the back-end technology environmental controls installed at our Hudson and Mercer coal facilities should meet the MACT's requirements. Some additional controls could be necessary at our Connecticut facility, pending engineering evaluation. In December 2011, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at our jointly-owned coal fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the fourth quarter of 2014. Our share of this investment is approximately $147 million.

- Cross-State Air Pollution Rule (CSAPR)—On July 6, 2011, the EPA issued the final CSAPR. CSAPR 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).

On August 21, 2012, the Court of Appeals vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. On October 5, 2012, the EPA filed a request for rehearing which the Court denied on January 24, 2013. What future actions the EPA will take regarding the Court's decision or the timing of those actions are unknown at this time. 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 2013 operations are similar to those in the past three years, it is expected that the impact to operations in New Jersey, New York and Connecticut from the temporary implementation of CAIR in 2013 will not be significant.

We currently anticipate that this rule will not have a material adverse impact to our capital investment program or our units' operations.

Climate Change

- CO_2 Regulation Under the CAA—In April 2010, the EPA and the National Highway Transportation Safety Board (NHTSB) jointly issued a final rule to regulate GHGs emissions from certain motor vehicles (Motor Vehicle Rule). Under the CAA, the adoption of the Motor Vehicle Rule would have automatically subjected many emission sources, including ours, to CAA permitting for new facilities and major facility modifications that increase the emission of GHGs, including CO_2. However, guidance issued by the EPA in March 2010 interpreted the CAA to require permitting for GHGs at other facilities, such as ours, only when the Motor Vehicle Rule was scheduled to take effect in January 2011. In May 2010, the EPA finalized a "Tailoring Rule" that would have phased in beginning in 2011, the application of this permitting requirement to facilities such as ours. The significance of the permitting requirement is that, in cases where a new source is constructed or an existing source undergoes a major modification, the owner of the facility would need to evaluate and perhaps install best available control technology (BACT) for GHG emissions. In November 2010, the EPA published guidance to state and local permitting authorities to undertake BACT determinations for new and modified emission sources. The guidance does not define the specific technology or technologies that should be considered BACT. The guidance does emphasize the use of energy efficiency, and specifically states that the technology of storing CO_2 under the earth, also known as carbon capture and storage, is not yet mature enough to be considered a viable alternative at this stage. On April 13, 2012, the EPA published the

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proposed New Source Performance Standards (NSPS) for GHG for new power plants and refineries. New or modified sources must employ BACT which is defined on a case-by-case basis and can be no less stringent than the applicable NSPS. Thus, for new power plants where the proposed NSPS identifies the applicable standard, if adopted as proposed, all permit decisions regarding BACT and application completeness should be made to reflect at least the level of stringency contained in those standards. The EPA is expected to move to regulation of existing electric generating units under the CAA. However, implementation of such regulations for existing sources is anticipated to be several years away.

- 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. Ten northeastern states, including New Jersey, New York and Connecticut, originally established RGGI to cap and reduce CO_2 emissions in the region. In general, these states adopted state-specific rules to enable the RGGI regulatory mandate in each state.

Applicable 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 (e.g. 2009, 2010, and 2011). Allowances are available through the auction or through secondary markets and were required to be submitted to states by March 2012 for the first compliance period.

The Governor of New Jersey withdrew New Jersey from RGGI beginning in 2012. Therefore, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances, but our generation facilities in New York and Connecticut remain subject to RGGI. The Governor's action to withdraw has been challenged by environmental groups in the New Jersey state court.

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

Water Pollution Control

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

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. In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule by July 27, 2012.

In April 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. On June 11, 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. On June 12, 2012, the EPA 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 April 2011 rule proposal. PSEG and industry trade associations submitted comments on both NODAs in July 2012. In July 2012, the EPA and

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environmental groups agreed to delay the deadline for finalization of the Rule to June 27, 2013 to allow for more time to address public comments and analyze data submitted in response to the NODAs.

If the rule were to be adopted as 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 Note 13. Commitments and Contingent Liabilities for additional information.

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 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. Under the contracts, the U.S. Department of Energy (DOE) was required to begin taking possession of the spent nuclear fuel by no later than 1998 but has not yet done so. The Nuclear Waste Policy Act of 1982 requires the DOE to perform an annual review of the Nuclear Waste Fee to determine whether that fee is set appropriately to fund the national nuclear waste disposal program. In October 2009, the DOE stated that the current fee of 1/10 cent per kWh was adequate to recover program costs. In March 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit seeking suspension of the Nuclear Waste Fee. On June 1, 2012, The U.S. Court of Appeals for the District of Columbia ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund. The court ordered the DOE to conduct a complete reassessment of this fee within six months. The DOE's assessment was completed in January 2013, and concluded that fee collection should be maintained. On January 31, 2013, motions were filed with the Court seeking to reopen the case and set a schedule for expedited review of the DOE fee adequacy report.

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.

- 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

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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 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 and the other two options are variations of a non-hazardous designation. All options communicate the EPA’s intent of ceasing wet ash transfer and instituting engineering controls on ash ponds and landfills to limit impact on human health and the environment. The outcome of the EPA rulemaking cannot be predicted. The EPA has not established a date for release of a final rule.

On April 5, 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. On May 15, 2012, the Utility Solid Waste Activities Group Policy Committee filed a Motion to Intervene in order to be in alignment with the EPA in defending against the environmental organizations' action. After May 2012, all parties agreed to a schedule for submitting briefs in this case. Motions for summary judgment remain pending.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Item 8. Financial Statements and Supplementary Data—Note 22. Financial Information by Business Segment.

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 document.

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—Our utility’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, the matter 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 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

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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 cybersecurity 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 will soon be 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 management audit and an affiliate transactions audit of PSE&G.

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 will receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas will 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 of the reasons 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.),

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- 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.

Also, 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, 2012, it may have had to provide approximately $654 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 2013.

- Our cost of coal and nuclear fuel may substantially increase—Our coal and nuclear units have a diversified portfolio of contracts and inventory that will 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.

- 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 and 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. 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. Multiple states are developing

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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.

- 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.

In June 2012, the United States Court of Appeals for the D.C. Circuit upheld the EPA finding that GHGs could reasonably be expected to endanger public health and welfare. However, the Court dismissed the action brought by individuals, local governments and interest groups alleging that various industries, including various energy companies, emitted GHGs, causing global climate change resulting in a variety of damages. Plaintiffs are expected to appeal to the United States Supreme Court.

In November 2012, the Ninth Circuit Court of Appeals refused to reconsider its decision not to rehear an Alaskan village's public nuisance lawsuit alleging that GHGs emissions from ExxonMobil Corporation and many other energy companies had made the village uninhabitable. The appellate court denied the petition for rehearing which accused these companies of causing GHGs emissions that contributed to global warming and alleged injury to the village. 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 us 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. These amounts have not been updated since our 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. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

- 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. Recent amendments to New Jersey law now place 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. While those amendments do not change our liability, they do impact the speed by which we will need to investigate contaminated properties, which could adversely impact cash flow.

The State of New Jersey has filed multiple lawsuits against parties, including us, who were alleged to be responsible for injuries to natural resources in New Jersey, including a site being remediated under our MGP program. 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. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities.

- 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 June 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 and the other two options are variations of a non-hazardous designation. All options communicate the EPA's intent of ceasing wet ash transfer and instituting engineering controls on ash ponds and landfills to limit impact on human health and the environment. 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 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 addition, legislative developments in the State of New Jersey have the potential to adversely impact RPM prices. In January 2011, New Jersey enacted a law establishing a LCAPP which provides for the construction of subsidized base load or mid-merit electric power generation. The LCAPP may have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis. PJM's Independent Market Monitor has released a report estimating that the impact of bidding 2,000 MW of capacity in New Jersey as a price taker could be a reduction in capacity market revenues to PJM suppliers of more than $2 billion in the first year.

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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 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. This rule has also opened up the construction of certain types of transmission to competition through elimination of the ROFR.

Changes in the current policies for building new transmission lines could result in additional competition to build transmission lines in our service territory in the future and would allow us to seek opportunities to build in other service territories.

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, and
- affiliates of other industrial companies.

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. Our ability to compete will also be impacted by:

- 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 conservation—It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, such as fuel cells, micro turbines, windmills and PV (solar) cells, to a level that is competitive with that of most central station electric production. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology could also alter the channels through which retail electric customers buy electricity, which could adversely affect our financial results.

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,

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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 the maintenance of 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, financing for projects and investments or funding the equity commitments required for such projects and investments in the future.

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 similar to the one experienced in 2008 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 lessen 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 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 affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow.

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Acts of war, terrorism or cybersecurity breaches 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 and information management systems for customer-related operations, could be direct or indirect targets or be affected by terrorist or other criminal activity.
Our businesses could also be impacted by cybersecurity breaches. Cybersecurity threats include:

- operational interference, such as attacks on our generation facilities, transmission lines or the power grid,
- information theft as to employees, shareholders, vendors and/or customers, such as personal financial and health records, and
- business system interruption or compromise.

Such events could severely disrupt business operations and prevent us from servicing our customers or collecting revenues. These events could also result in significant expenses to repair security breaches or system damage as well as increased capital, insurance and operating costs, including increased security costs for our facilities. A breach of certain business systems could affect our ability to record, process and/or report financial information correctly. In addition, new or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.
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 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.

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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. For additional information relating to these leases, see Item 7. MD&A—Critical Accounting Estimates and Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables.

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.

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Generation Facilities
Power
As of December 31, 2012, Power's share of summer installed 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	1,174	100%	1,174	Nuclear	Base Load
Salem 1 & 2	NJ	2,326	57%	1,335	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,245	50%	1,123	Nuclear	Base Load
Total Nuclear		5,745		3,632		
Combined Cycle:						
Bergen	NJ	1,183	100%	1,183	Gas	Load Following
Linden	NJ	1,236	100%	1,236	Gas	Load Following
Bethlehem	NY	757	100%	757	Gas	Load Following
Total Combined Cycle		3,176		3,176		
Combustion Turbine:						
Essex	NJ	617	100%	617	Gas	Peaking
Edison	NJ	504	100%	504	Gas	Peaking
Kearny	NJ	463	100%	463	Gas	Peaking
Burlington	NJ	557	100%	557	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	NJ	38	57%	22	Oil	Peaking
New Haven Harbor	CT	129	100%	129	Gas/Oil	Peaking
Bridgeport Harbor	CT	12	100%	12	Oil	Peaking
Total Combustion Turbine		2,922		2,906		
Pumped Storage:						
Yards Creek (C)	NJ	400	50%	200		Peaking
Total Power Plants		18,201		13,226		

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

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PSE&G

As of December 31, 2012, PSE&G had 73 MW of installed solar capacity throughout New Jersey.

Energy Holdings

Energy Holdings had investments in the following generation facilities as of December 31, 2012:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
Kalaeloa	HI	209	50%	105	Oil
Hackettstown	NJ	2	100%	2	Solar
Wyandot	OH	12	100%	12	Solar
Jacksonville	FL	15	100%	15	Solar
Queen Creek	AZ	25	100%	25	Solar
Milford	DE	15	100%	15	Solar
Total Operating Power Plants		278		174	

Transmission and Distribution Facilities

As of December 31, 2012, PSE&G's electric transmission and distribution system included 23,856 circuit miles, of which 8,357 circuit miles were underground, and 838,236 poles, of which 546,614 poles were jointly-owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 2012, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2012, 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 2,790,500 therms (270,932,330 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	670,500
Camden LPG	Camden, NJ	320,000
Central LPG	Edison, NJ	900,000
Harrison LPG	Harrison, NJ	900,000
Total		2,790,500

As of December 31, 2012, PSE&G owned and operated 17,713 miles of gas mains, owned 12 gas distribution headquarters and two subheadquarters, 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, 2012, 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.

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ITEM 3. LEGAL PROCEEDINGS

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

Con Edison (Con Ed)

In 2001, Con Ed filed a complaint with the FERC against PSE&G, PJM and NYISO asserting a failure to comply with agreements between PSE&G and Con Ed covering 1,000 MW of transmission. On September 16, 2010, the FERC approved a settlement agreement entered into by PSE&G, Con Ed, PJM, NYISO and others. This settlement provides the basis for moving forward with Con Ed after the current contracts expire in 2012 and settles all issues associated with the existing contracts, including cases pending in the D.C. Circuit Court of Appeals. However, dismissal of these court cases is contingent upon receipt of a final, non-appealable order from the FERC. One party to the proceeding sought rehearing of the FERC approval order, which the FERC denied in an order issued on April 8, 2011. The party then appealed this decision to the D.C. Circuit Court of Appeals. This appeal is pending.

Electric Discount and Energy Competition Act (Competition Act)

In 2007, PSE&G and Transition Funding were served with a purported class action complaint (Complaint) in New Jersey Superior Court challenging the constitutional validity of certain stranded cost recovery provisions of the Competition Act, seeking injunctive relief against continued collection from PSE&G's electric customers of the Transition Bond Charge (TBC) of Transition Funding, as well as recovery of TBC amounts previously collected. The Superior Court subsequently granted PSE&G's motion to dismiss the Complaint, which dismissal was upheld by the Appellate Division.

In July 2007, the same plaintiff also filed a petition with the BPU requesting review and adjustment to PSE&G's recovery of the same stranded cost charges. In June 2010, the BPU granted PSE&G's motion to dismiss, and the plaintiff/petitioner subsequently appealed this dismissal to the Appellate Division. In June 2012, the Appellate Division affirmed the BPU's decision, concluding that the BPU had correctly found that the plaintiff's claims failed as a matter of law. The petitioner subsequently filed a Notice of Petition for Certification with the New Jersey Supreme Court. By order dated November 16, 2012, the New Jersey Supreme Court denied this Notice. On February 11, 2013, the Court denied the plaintiff's subsequent motion for reconsideration.

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) Claim made in 1985 by the U.S. Department of the Interior under CERCLA with respect to the Pennsylvania Avenue and Fountain Avenue municipal landfills in Brooklyn, New York, for damages to natural resources. The United States Government alleges damages of approximately $200 million. To PSE&G's knowledge there has been no action on this matter since 1988.

(2) Various Spill Act directives were issued by the NJDEP to 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.

(3) 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.

(4) 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

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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.

(5) In 1996, Morton International, Inc., a subsidiary of The Dow Chemical Company, filed a lawsuit against the former customers of a former mercury refining operation located on the banks of Berry's Creek in Wood-Ridge, New Jersey. The lawsuit seeks to recover cleanup costs incurred and to be incurred in remediating the site. PSE&G was among the former customers sued based on allegations that mercury originating at its Kearny Generating Station was sent to the site for refining.

(6) 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 be completed in approximately five years at a total cost of 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 to conduct the RI/FS.

(7) 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 NJDEP Solid Waste Regulations.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

Our common stock is listed on the New York Stock Exchange, Inc. As of December 31, 2012, there were 78,842 registered holders.
The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2007 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.

	2007	2008	2009	2010	2011	2012
PSEG	$100.00	$61.55	$73.15	$73.09	$79.08	$76.68
S&P 500	$100.00	$63.06	$79.70	$91.68	$93.63	$108.55
DJ Utilities	$100.00	$72.22	$81.18	$86.41	$103.34	$104.70
S&P Electrics	$100.00	$74.20	$76.68	$76.68	$95.92	$95.37

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

Common Stock	High	Low	Dividend per Share
2012			
First Quarter	$33.25	$29.59	$0.3550
Second Quarter	$32.51	$28.92	$0.3550
Third Quarter	$34.07	$31.19	$0.3550
Fourth Quarter	$33.36	$29.05	$0.3550
2011			
First Quarter	$33.12	$30.15	$0.3425
Second Quarter	$34.22	$30.30	$0.3425
Third Quarter	$35.48	$27.97	$0.3425
Fourth Quarter	$34.96	$30.60	$0.3425

On February 19, 2013, our Board of Directors approved $0.36 per share of common stock dividend for the first quarter of 2013. This reflects an indicated annual dividend rate of $1.44 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 2012:

Three Months Ended December 31, 2012	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$—
November 1-November 30	50,000	$30.36
December 1-December 31	31,000	$30.01

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2012:

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	
Equity compensation plans approved by security holders	2,945,400	$34.19	17,013,520	(A)
Equity compensation plans not approved by security holders	—	$—	3,589,032	(B)
Total	2,945,400	$34.19	20,602,552	

(A) Shares issuable under our Long-Term Incentive Plan.
(B) Shares issuable under our Employee Stock Purchase Plan.

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 2012 and Future Outlook.

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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 2012 and Future Outlook.

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					
	2012	2011	2010	2009	2008
Years Ended December 31,	Millions, except Earnings per Share				
Operating Revenues	$9,781	$11,079	$11,793	$12,035	$12,609
Income from Continuing Operations (A)	$1,275	$1,407	$1,557	$1,594	$918
Net Income	$1,275	$1,503	$1,564	$1,592	$1,188
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$2.52	$2.78	$3.08	$3.15	$1.81
Diluted (A)	$2.51	$2.77	$3.07	$3.14	$1.81
Net Income					
Basic	$2.52	$2.97	$3.09	$3.15	$2.34
Diluted	$2.51	$2.96	$3.08	$3.14	$2.34
Dividends Declared per Share	$1.42	$1.37	$1.37	$1.33	$1.29
As of December 31:					
Total Assets	$31,725	$29,821	$29,909	$28,678	$29,049
Long-Term Obligations (B)	$6,701	$7,482	$7,847	$7,679	$8,044

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(A) Income from Continuing Operations for 2011 and 2008 includes after-tax charges of $170 million and $490 million, respectively, 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.

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ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), 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 three reportable segments, which are:

- Power, our wholesale energy supply company that integrates its 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,
- PSE&G, our public utility company which provides transmission and distribution of electric energy and gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and
- Energy Holdings, which principally owns and manages a portfolio of lease investments and solar generation projects.

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 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 2012 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 2012 AND FUTURE OUTLOOK

2012 Overview

During 2012, our financial results continued to be adversely impacted by lower prices for electricity and natural gas in the markets we serve. Electricity prices remained low due to a combination of a slow recovery in demand growth and sustained low natural gas prices. The slow economic recovery negatively impacts utility sales, and the wholesale energy and capacity markets in which we operate. The continued decline in wholesale natural gas prices resulting from greater supply from shale production has further contributed to the steady decline in the wholesale price of electricity.

In the face of reduced pricing and lower demand for electricity, we continued to pursue our three-pronged strategy of operational excellence, financial strength and disciplined investment. Our focus has been to change the business mix of our operations with increased investments in our regulated utility. Through our regulated utility operations, we secured higher and more stable transmission revenues in 2012 resulting from our annual transmission formula rate update filing with the Federal Energy Regulatory Commission (FERC) and made additional solar and energy efficiency investments in New Jersey, on which we receive contemporaneous returns. Through allocating capital to transmission and distribution infrastructure projects, we were able to take advantage of a low interest rate environment and tap into an available labor pool in the region, while enhancing the reliability of our service to our customers. Additionally, these sources of revenue allowed us to partially offset the impact of lower prices for electricity and natural gas, while the reduction in supply costs allows us to continue to invest in infrastructure improvements without raising our utility customers' rates.

While we have been successfully increasing our regulated utility earnings, we have not fully compensated for the reduction in generation earnings. Over the past few years, we experienced a decline in wholesale energy prices. Basic Generation Service (BGS) rates also declined, resulting in lower revenues for our generation business. As BGS rates reached a level closer to current spot market prices, customer migration away from BGS supply contracts continued in 2012, but at a slower pace as there was less incentive to switch to third party suppliers.

In addition, at year-end 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. We received an order from the New Jersey Board of Public Utilities (BPU) allowing us to defer incurred, uninsured, incremental storm restoration costs associated with our gas and electric distribution systems.

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As of December 31, 2012, Power had incurred approximately $85 million in costs related to Superstorm Sandy, primarily comprised of repairs at certain generating stations and damage to materials and supplies, both at our fossil fleet. All the costs were recognized in Operation and Maintenance Expense, offset by $19 million of a pending future recovery of insurance proceeds. Power estimates that it will incur additional future costs primarily relating to repairs to, and replacement of, equipment and property up to approximately $215 million.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in Operation and Maintenance Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. PSE&G recognized $6 million of insurance proceeds.

We are working with our insurance carriers with regard to other losses and expenses due to the storm but no assurances can be given relative to the timing or amount of insurance recovery. For additional information on the impacts of Superstorm Sandy, see Item 8. Financial Statements and Supplementary Data-Note 13. Commitments and Contingent Liabilities.

There have also been significant regulatory and legislative developments during the year which may affect our operations and financial results in the future as new rules and regulations are developed. Competitive wholesale power market design is of particular importance to our results. Through litigation and the regulatory processes, we advocated for policies and rules in response to subsidized generation and procurement activities in New Jersey in connection with the Long-Term Capacity Agreement Pilot Program (LCAPP), and in Maryland through the Maryland Public Service Commission's Request for Proposal. After a favorable stakeholder vote, PJM filed proposed modifications to the Minimum Offer Price Rule (MOPR) with the FERC. In February 2013, the FERC issued a deficiency letter to PJM seeking additional information regarding the proposed MOPR changes. If the FERC approves the proposal, these modifications should significantly improve the MOPR rules and appropriately reduce the ability for subsidized generation assets to artificially suppress wholesale market prices. Litigation with respect to the New Jersey LCAPP and Maryland's efforts to subsidize new generation and challenges to the BPU's implementation of LCAPP continues. See Item 1. Business, Federal Regulation, FERC - Capacity Market Issues for further information.

We continued to monitor and advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA). The EPA is proceeding to implement its regulatory initiatives but the outcome of judicial review remains uncertain. The EPA's 316(b) rule on cooling water intake could adversely impact future nuclear and fossil operations and costs. However, we believe our generation business remains well-positioned for Clean Air Act regulations, if and when they are implemented. For additional information on the potential impacts of the 316(b) rule, see Item 8. Financial Statements and Supplementary Data-Note 13. Commitments and Contingent Liabilities.

Another regulatory development in 2012 that could have a material impact on our business are FERC rules under Order 1000, which altered the right of first refusal previously held by incumbent utilities to build all transmission within their respective service territories. We are opposing these rules in litigation and have worked with PJM to develop implementing rules that mitigate the impact of Order 1000. We cannot predict the final outcome or impact on us; however, specific implementation of Order 1000 within our service territory may expose us to competition for certain types of transmission projects, while at the same time affording us opportunities to construct transmission outside of our service territory. See Item 1. Business, Federal Regulation, FERC -Transmission Regulation.

We are making progress in addressing these challenges, but regulatory uncertainty remains a concern.

In 2012, our continued focus on operational excellence provided the foundation for our financial strength, in turn enabling us to invest in a disciplined way for growth, providing value for our customers, employees and shareholders and allowing us to best succeed in a sustained low electricity price environment. Some specific highlights in the areas of operational excellence, financial strength and disciplined investment in 2012 are discussed in more detail below.

Operational Excellence

We seek to emphasize operational performance while developing opportunities in our competitive and regulated businesses. Low commodity prices continue to stress margins, but the flexibility of our generating fleet has allowed us to take advantage of market opportunities as we remain diligent in managing costs. In 2012, we

- constructed approximately $656M million of gross plant additions to our transmission assets currently in service,
- continued to achieve high nuclear capacity factors, which averaged 91.1% for our nuclear fleet in 2012,
- improved fossil plant summer output,
- realized high combined cycle gas turbine fleet capacity utilization factors,

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- optimized fleet-switching from coal to gas to improve dispatch economics,
- extended collective bargaining agreements with four of our labor unions for four years,
- implemented more efficient plant staffing,
- were awarded the 2011 National Reliability Excellence Award for “demonstrating sustained leadership, innovation and achievement in the area of electric reliability," representing the fifth time in eight years we received this recognition, and eleven straight years that we garnered the ReliabilityOne Award for the Mid-Atlantic region, and
- received other award recognition for reliability and outage response.

Financial Strength

Our financial metrics remained strong in 2012. We maintained

- a strong balance sheet and operating cash flow,
- substantial liquidity resources, including total credit capacity of $4.3 billion and $379 million of cash on hand as of December 31, 2012, with a portion of available credit facilities extending until 2017,
- stable credit ratings,
- dividend payments of $1.42 per share for 2012, representing a change in our dividend policy moving from a strict earnings payout based approach to one that takes into consideration the growing contribution to earnings and cash from our regulated operations and continued cash flow from our generation business, and
- a well-funded position for our pension obligation, having made a $224 million contribution to our pension plan in 2012.

We also funded our capital program with internally generated cash and external debt financing.

In addition, we entered into a closing agreement settling our dispute with the Internal Revenue Service (IRS) over certain international leveraged lease transactions with finality for all tax periods in which we realized tax deductions from these transactions. Also, we executed settlement agreements covering all audit issues for tax years 1997 through 2006, concluding ten years of open audits for us. For additional information on the IRS audit settlements, see Item 8. Financial Statements and Supplementary Data-Note 20. Income Taxes.

Disciplined Investment

We seek to invest in areas that complement our existing businesses and provide attractive 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. We also have several projects where we are investing to continue to improve our operational performance. As noted above, over the past few years, we have shifted our focus to investing at the utility. Our capital expenditure forecast includes approximately $6.1 billion in spending over the next three years, 80% of which is at PSE&G. In addition, in 2012 we:

- invested approximately $1.1 billion in transmission infrastructure projects,
- completed the Peach Bottom steam path retrofit,
- added 400 MW of additional capacity with new peaking plants in New Jersey and Connecticut,
- completed solar projects in Arizona and Delaware, with the expectation to complete an additional Arizona solar project in 2013,
- made additional investments in our Capital Infrastructure Program (CIP II) and our Energy Efficiency and Demand Response Programs, and
- obtained BPU and NJDEP approvals of the North Central Reliability transmission project.

On February 20, 2013, we filed a petition with the BPU describing $3.9 billion of improvements we recommend making to our electric and gas distribution systems over a ten year period to harden and improve resiliency for the future. In addition, we anticipate investing an additional $1.5 billion in improvements to our transmission system for the same reason. See Capital Requirements for additional information.

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There is no guarantee that our projects currently underway or any future initiatives will be achieved since many issues need to be favorably resolved, such as regulatory approvals. Delays in the construction schedules of our projects could impact their costs as well as the timing of expected revenues.

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 and to respond to the issues and challenges described below and take advantage of these and other regulatory and legislative initiatives. In order to do this, we must continue to:

- focus on controlling costs while maintaining our safety, reliability and compliance standards,
- successfully re-contract our open supply positions,
- execute our capital investment program, including investments for growth that yield contemporaneous and attractive risk-adjusted returns while enhancing the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and FERC of market design rules that continue to protect competition and achieve appropriate RPM and BGS pricing, and
- reach out to and engage multiple stakeholders, including regulators, government officials, customers and investors.

For 2013 and beyond, the key issues and challenges we expect our business to confront include

- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- challenges to competitive markets, including support for subsidized generation in many states, particularly in New Jersey,
- customer migration away from our BGS supply contracts,
- uncertainty in the national and regional economic recovery and continuing customer conservation efforts, which impact customer demand,
- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation,
- 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 and improvements,
- compressed margins and reduced utilization at coal plants,
- uncertain pension expenses and funding requirements given market volatility,
- liquidating the remaining portfolio of non-core assets where possible, while managing risk,
- monitoring financially stressed power plant leveraged lease investments, and
- successfully managing the transition to our operation of Long Island Power Authority's (LIPA) transmission and distribution system.

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RESULTS OF OPERATIONS

	Years Ended December 31,		
	2012	2011	2010
Earnings (Losses)	Millions		
Power (A)	$647	$1,002	$1,136
PSE&G (A) (B)	528	521	359
Energy Holdings (C)	86	(134)	49
Other (D)	14	18	13
PSEG Income from Continuing Operations	1,275	1,407	1,557
Income (Loss) from Discontinued Operations, Including Gain on Disposal (E)	—	96	7
PSEG Net Income	$1,275	$1,503	$1,564

	Years Ended December 31,		
Earnings Per Share (Diluted)	2012	2011	2010
PSEG Income from Continuing Operations	$2.51	$2.77	$3.07
Income from Discontinued Operations, Including Gain on Disposal (E)	—	0.19	0.01
PSEG Net Income	$2.51	$2.96	$3.08

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

(B) PSE&G’s results in 2010 include an after-tax charge of $72 million related to an agreement to refund previous Market Transition Charge (MTC) collections in the succeeding two years.

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

(D) Other includes parent company interest and financing costs, donations, certain administrative and general expenses.

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

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

- 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 Operation and Maintenance 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.

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The 2011 year-over-year decrease in our Income from Continuing Operations was driven by the following:

- the $170 million after-tax charge on leveraged leases related to Dynegy,
- the absence of an after-tax charge of $72 million related to an agreement to refund previous MTC collections in the succeeding two years,
- lower average pricing and volumes for electricity sold under our BGS contracts,
- lower realized prices and/or lower sales volumes in the various power pools,
- higher interest costs and depreciation expense related to the completion of installation of back-end technology at two of our fossil plants, and
- the absence of realized gains recognized in 2010 due to restructuring of the investments in our Rabbi Trust.

The decreases were partially offset by:

- favorable amounts related to the MTM activity reported below,
- an increase in revenues from new wholesale contracts entered into in the first half of 2011, and
- lower Operation and Maintenance costs primarily due to lower pension and OPEB costs.

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 mark-to-market (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, 2012, 2011 and 2010 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2012	2011	2010
	Millions, after tax		
NDT Fund and Related Activity	$52	$50	$46
Non-Trading MTM Gains (Losses)	$(10)	$107	$(1)

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding charges related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 23. Related-Party Transactions.

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	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
	Millions			Millions	%	Millions	%
Operating Revenues	$9,781	$11,079	$11,793	$(1,298)	(12)	$(714)	(6)
Energy Costs	3,719	4,747	5,261	(1,028)	(22)	(514)	(10)
Operation and Maintenance	2,632	2,481	2,504	151	6	(23)	(1)
Depreciation and Amortization	1,054	976	955	78	8	21	2
Income from Equity Method Investments	12	4	4	8	N/A	—	—
Other Income and (Deductions)	162	135	158	27	20	(23)	(15)
Other-Than-Temporary Impairments	18	22	11	(4)	(18)	11	100
Interest Expense	423	475	472	(52)	(11)	3	1
Income Tax Expense	736	977	1,059	(241)	(25)	(82)	(8)
Income from Discontinued Operations, including Gain on Disposal, net of tax	—	96	7	(96)	(100)	89	N/A

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

Power

	Years Ended December 31,			Increase/ (Decrease)	Increase/ (Decrease)
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	Millions				
Income from Continuing Operations	$647	$1,002	$1,136	$(355)	$(134)
Income (Loss) from Discontinued Operations, net of tax	—	96	7	(96)	89
Net Income	$647	$1,098	$1,143	$(451)	$(45)

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

- lower average prices realized on generation sold into the PJM and New York (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,
- lower average pricing and lower volumes of electricity sold under our BGS contracts, net of lower cost to serve,
- lower volumes on wholesale load contracts in PJM, lower operating reserve, ancillary and Reliability Must Run (RMR) revenues primarily in PJM and New England,
- lower average pricing and volumes of gas sold under our BGSS contracts, net of lower cost to serve, and
-

- higher Operation and Maintenance Expense due to damage to our generation infrastructure, primarily our fossil fleet, from Superstorm Sandy and higher refueling and maintenance costs at our nuclear plants.

These decreases were partially offset by

- lower planned outages and maintenance costs in 2012 at certain of our fossil plants, and

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- lower interest expense due to the maturity of Senior Notes in April 2011 and the early redemption of Senior Notes in December 2011.

For the year ended December 31, 2011, the primary reasons for the decrease in Income from Continuing Operations were

- lower average pricing and lower volumes of electricity sold under our BGS contracts, as a result of customer migration,
- higher Operation and Maintenance expense related to planned outage work at certain of our fossil plants, and
- higher depreciation expense related to the completion of installation of back-end technology at two of our fossil plants.

The decreases were partially offset by

- favorable amounts related to the MTM activity,
- favorable results from our coal optimization efforts, and
- an increase from new wholesale contracts entered into in the first half of 2011.

The year-over-year detail for these variances for these periods is discussed below:

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
Power	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
	Millions			Millions	%	Millions	%
Operating Revenues	$4,865	$6,143	$6,558	$(1,278)	(21)	$(415)	(6)
Energy Costs	2,383	3,046	3,374	(663)	(22)	(328)	(10)
Operation and Maintenance	1,122	1,102	1,046	20	2	56	5
Depreciation and Amortization	237	224	175	13	6	49	28
Other Income (Deductions)	109	111	117	(2)	(2)	(6)	(5)
Other-Than-Temporary Impairments	18	20	9	(2)	(10)	11	N/A
Interest Expense	134	175	157	(41)	(23)	18	11
Income Tax Expense	433	685	778	(252)	(37)	(93)	(12)
Income (Loss) from Discontinued Operations	—	96	7	(96)	(100)	89	N/A

Year ended December 31, 2012 as compared to 2011

Operating Revenues decreased $1,278 million due to

Generation Revenues decreased $975 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 New England (NE) regions,
- 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.

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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 $20 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 gas-fired Bethlehem Energy Center (BEC) in New York, gas-fired Bergen and Linden facilities, coal/gas-fired Hudson and Mercer coal/gas-fired plants in New Jersey, and 23%-owned coal-fired Conemaugh plant in Pennsylvania, 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 $13 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 on June 1, 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.

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 $41 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 on their June 1, 2012 in-service date.

Income Tax Expense decreased $252 million in 2012 due primarily to lower pre-tax income.

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

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plants for 2011 and 2010, including the gains in 2011 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.

Year ended December 31, 2011 as compared to 2010

Operating Revenues decreased $415 million due to

Gas Supply Revenues decreased $290 million due primarily to

- a net decrease of $283 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in 2011 due to warmer average temperatures during the fourth quarter of 2011,
- a net decrease of $7 million due primarily to lower average gas prices partially offset by higher sales volumes to third party customers.

Generation Revenues decreased $143 million due primarily to

- a net decrease of $305 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts as a result of customer migration,
- a decrease of $70 million due primarily to lower capacity payments from the various power pools resulting from lower market prices, and
- a decrease of $8 million due to lower operating reserve revenue in 2011.

These were partially offset by

- an increase of $136 million from new wholesale load contracts in the PJM and NE regions commencing in January 2011 and April 2011, respectively, net of lower average realized prices in the NE region, and
- higher net revenues of $108 million due primarily to MTM gains on economic hedging activity of $228 million, partially offset by lower realized prices in the PJM and NY power pools and lower volumes of generation sold in the PJM and NE power pools of $120 million.

Trading Revenues increased $18 million due primarily to lower net losses in 2011 on certain electric energy supply contracts as well as the discontinuation of trading activities in the second quarter of 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel purchases 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 $328 million due to

- Gas costs decreased $282 million, principally related to obligations under the BGSS contract, reflecting lower average gas inventory costs coupled with lower sales volumes in 2011 due to warmer average temperatures during the fourth quarter of 2011.
- Generation costs decreased by $46 million due primarily to $211 million of lower fuel costs, including $251 million of lower fossil fuel costs primarily reflecting the utilization of lower volumes of both coal and oil, favorable results from our coal optimization efforts, and lower natural gas prices, partially offset by higher MTM losses and higher nuclear fuel costs in 2011. The decrease was also attributable to $16 million of lower emission charges, including $10 million of lower impairment charges related to excess SO_2 emission allowances. These decreases were partially offset by an increase of $153 million in higher energy purchases in 2011 in the PJM and NE power pools as the result of lower generation and the need to meet higher load contract demand in 2011 and $23 million of higher operating reserve obligations in the PJM region.

Operation and Maintenance increased $56 million due primarily to

- a net increase of $47 million due largely to planned outage costs, including hot gas path inspection outage costs at our BEC and Linden facilities as well as higher outage costs at our Bergen, and Keystone facilities, partially offset by higher outage and repair costs at certain of our other fossil plants in 2010,
- $20 million of costs incurred for the cancellation and renegotiation of a major contractual agreement for parts and services for our combined cycle Bethlehem Energy (BEC) facility in New York and Linden and Bergen facilities in New Jersey, and

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- a net increase of $3 million due to refurbishment projects at our Salem nuclear facilities,
- partially offset by a decrease of $13 million due to a decrease in pension and OPEB costs tempered by higher labor costs and incentive awards.

Depreciation and Amortization increased $49 million due primarily to

- a $37 million increase due to completion of installation of back-end technology at the end of 2010 at our Mercer and Hudson generating facilities, and
- a $12 million increase due to higher depreciable asset bases at Nuclear and Fossil.

Other Income and (Deductions) The net decrease of $6 million was due primarily to

- a $17 million premium paid on the early extinguishment of 6.95% Senior Notes due in June 2012, and
- the absence of $7 million of gains realized in 2010 from restructuring the Rabbi Trust,
- partially offset by higher net realized gains of $19 million on our NDT Fund.

Other-Than-Temporary Impairments increased $11 million due primarily to higher impairments on the NDT Fund in 2011.

Interest Expense increased $18 million due primarily to

- Higher interest expense of $49 million resulting primarily from the installation by year-end 2010 of back-end technology at our Mercer and Hudson stations for which we had been allowed to capitalize interest costs in 2010 while such projects were under construction,
- partially offset by lower interest expense of $30 million due primarily to the redemption of $606 million of 7.75% Senior Notes in early April 2011 and lower debt issuance costs of $3 million.

Income Tax Expense decreased $93 million in 2011 due primarily to lower pre-tax income.

Income (Loss) from Discontinued Operations

See explanation above for year ended December 31, 2012 as compared to 2011.

PSE&G

	Years Ended December 31,			Increase	Increase
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	Millions				
Income from Continuing Operations	$528	$521	$359	$7	$162
Net Income	$528	$521	$359	$7	$162

For the year ended December 31, 2012, the primary reasons for the increase in Income from Continuing Operations were

- higher transmission revenues due to increased investments in transmission projects, and
- tax benefits related to settlement of IRS audits,
- partially offset by higher Operation and Maintenance expense, including higher storm costs and higher pension and OPEB expenses.

For the year ended December 31, 2011, the primary reasons for the increase in Income from Continuing Operations were

- the absence of a $72 million after-tax charge recorded in June 2010 related to the refund of previous MTC collections,
- higher annualized base rates for electric and gas delivery as well as transmission, and
- lower Operation and Maintenance expense, largely due to lower pension and OPEB expenses.

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The year-over-year details for these variances for these periods are discussed below:

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
PSE&G	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
	Millions			Millions	%	Millions	%
Operating Revenues	$6,626	$7,326	$7,869	$(700)	(10)	$(543)	(7)
Energy Costs	3,159	3,951	4,655	(792)	(20)	(704)	(15)
Operation and Maintenance	1,508	1,372	1,442	136	10	(70)	(5)
Depreciation and Amortization	778	719	750	59	8	(31)	(4)
Taxes Other Than Income Taxes	98	133	136	(35)	(26)	(3)	(2)
Other Income (Deductions)	47	21	23	26	N/A	(2)	(9)
Other-Than-Temporary Impairments	—	1	—	(1)	(100)	1	100
Interest Expense	295	310	318	(15)	(5)	(8)	(3)
Income Tax Expense	307	340	232	(33)	(10)	108	47

Year ended December 31, 2012 as compared to 2011

Operating Revenues decreased $700 million due primarily to

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 Non-Utility Generation (NUG) energy and collections of Non-Utility Generation Charges (NGC) due primarily to lower prices. BGS sales decreased 12% due primarily to customer migration to third party suppliers (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 $81 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 Transitional Energy Facilities Assessment (TEFA) revenue of $22 million due to a lower TEFA rate and lower sales volumes of $13 million, partially offset by higher Solar, Energy Efficiency and Conservation Program (Solar/EE) revenue of $20 million and higher Capital Infrastructure Program (CIP) revenue of $9 million.
- Gas distribution revenues increased $4 million due primarily to higher Weather Normalization Clause (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 Securitization Transition Charge (STC) revenues of $19 million, partially offset by lower Societal Benefit Charges (SBC) of $6 million and a lower Margin Adjustment Clause (MAC) of $2 million. The changes in STC and SBC 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, MAC or STC collections.

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.

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Operation and Maintenance increased $136 million, of which the most significant components were
- a $32 million increase in costs recognized related to SBC, Solar/EE and CIP,
- a $27 million increase in pension and other postretirement benefits (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. See Note 9. Changes in Capitalization for details.

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

Year ended December 31, 2011 as compared to 2010

Operating Revenues decreased $543 million due primarily to

Commodity Revenue decreased $704 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.

- Electric revenues decreased $397 million due primarily to $466 million in lower BGS revenues, partially offset by $69 million in higher revenues from the sale of NUG energy and collections of NGC due primarily to higher prices. BGS sales decreased 16% due primarily to customer migration to TPS; in contrast, delivery sales decreased only 2%.
- Gas revenues decreased $307 million due to lower BGSS prices of $259 million and lower BGSS volumes of $48 million. The average price of gas was 3% lower in 2011 than in 2010.

Delivery Revenues increased $74 million due primarily to an increase in prices for electric and gas distribution and transmission.

- Transmission revenues were $42 million higher due primarily to increased investments in transmission projects.
- Gas distribution revenues increased $32 million due primarily to higher WNC revenue of $19 million and the impact of base rate increases of $17 million, partially offset by lower CIP revenue of $5 million.
- Electric distribution revenues were flat due primarily to the impact of base rate increases of $17 million and higher CIP revenue of $1 million, offset by lower sales volumes of $18 million.

Clause Revenues increased $73 million due primarily to the absence of $122 million charge recorded in June 2010 related to our agreement to refund previous MTC collections over two years and higher SBC and MAC of $49 million, partially offset by lower STC revenues of $98 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 earns no margins on SBC, STC or MAC collections.

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

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Energy Costs decreased $704 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $397 million due to $405 million in lower BGS and NUG volumes and $75 million of lower BGS and NUG prices, partially offset by $83 million for increased deferred cost recovery. BGS and NUG volumes decreased 14% due primarily to customer migration to TPS.
- Gas costs decreased $307 million or 19% due to $259 million or 16% in lower prices and $48 million or 3% in lower sales volumes due primarily to weather.

Operation and Maintenance decreased $70 million due primarily to

- a $71 million decrease in pension and OPEB expenses,
- $20 million of lower net deferred expenses associated with SBC, Regional Greenhouse Gas Initiative and Stimulus clauses, and
- the absence of $15 million in expenses relating to 2010 rate case disallowances.

These were partially offset by

- a $9 million increase in storm restoration work,
- a $6 million increase in costs relating to tree trimming,
- a $3 million increase in bad debt expense, and
- a $3 million increase in incentive payments.

Depreciation and Amortization decreased $31 million due primarily to

- a decrease of $63 million for amortization of Regulatory Assets,
- partially offset by an increase of $28 million for additional plant in service, and an increase of $3 million in net other charges.

Other Income and (Deductions) experienced no material change.

Other-Than-Temporary Impairments experienced no material change.

Interest Expense decreased $8 million due primarily to lower average debt balances.

Income Tax Expense increased $108 million due primarily to higher pre-tax income.

Energy Holdings

	Years Ended December 31,			Increase/ (Decrease)	Increase/ (Decrease)
	2012	2011	2010	2012 vs. 2011	2011 vs. 2010
	Millions				
Income from Continuing Operations	$86	$(134)	$49	$220	$(183)
Net Income	$86	$(134)	$49	$220	$(183)

For the year ended December 31, 2012, the primary reasons for the increase in Income from Continuing Operations were

- the absence of the $170 million after-tax charge on leveraged leases related to Dynegy in 2011 and the settlement proceeds received in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 8. Financing Receivables), and
- the tax benefits related to the settlement of IRS tax audits in the first quarter of 2012.

For the year ended December 31, 2011, the primary reason for the decrease in Income from Continuing Operations was

- the $170 million after-tax charge on leveraged leases related to Dynegy.

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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 three direct 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 100% of commercial paper 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 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. 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 hedging activities 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, 2012, our operating cash flow decreased by $770 million. For the year ended December 31, 2011, our operating cash flow increased by $1,393 million. The net changes were due to net changes from our subsidiaries as discussed below.

Power

Power’s operating cash flow decreased $433 million from $1,812 million to $1,379 million for the year ended December 31, 2012, as compared to 2011, primarily resulting from lower earnings and a $173 million decrease from lower net collections of counterparty receivables, partially offset by

- a decrease of $57 million in benefit plan funding,
- a $73 million decrease in spending for fuel, materials and supplies, and
- a $246 million decrease in net payment of counterparty payables.

Power’s operating cash flow increased $246 million from $1,566 million to $1,812 million for the year ended December 31, 2011, as compared to 2010, primarily resulting from

- an increase of $368 million due to lower tax payments, primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information), and
- a $302 million increase from net collection of counterparty receivables.

These were partially offset by

- a $171 million increase in net payment of counterparty payables,

- a $161 million net increase in spending on fuel inventories, and
- lower earnings.

PSE&G

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.

PSE&G's operating cash flow increased $765 million from $1,011 million to $1,776 million for the year ended December 31, 2011, as compared to 2010, due primarily to higher earnings combined with

- an increase of $587 million due to lower tax payments, primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Item 8. Financial Statements and Supplementary Data—Note 20. Income Taxes for additional information), and
- an increase of $273 million due to higher collections of customer billings,
- partially offset by a decrease of $108 million in net other working capital.

Energy Holdings

Energy Holdings' operating cash flow increased $149 million for the year ended December 31, 2012, as compared to 2011, primarily due to lower tax payments in 2012 related to the absence of lease sale activity in 2012 and tax benefits related to settlement of IRS audits.

Energy Holdings' operating cash flow increased $341 million for the year ended December 31, 2011, as compared to 2010, primarily due to lower tax payments in 2011 related to less lease sale activity in 2011.

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, 2012 were as follows:

Company/Facility	As of December 31, 2012		
	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$1,000	$4	$996
Power	2,700	165	2,535
PSE&G	600	276	324
Total	$4,300	$445	$3,855

As of December 31, 2012, our credit facility capacity is 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, 2012, $263 million was outstanding. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingent Liabilities and Note 14. Schedule of Consolidated Debt.

Long-Term Debt Financing

PSE&G had $150 million of 5.00% Medium Term Notes mature in January 2013 and issued $400 million of 3.80% Secured Medium-Term Notes, Series H, due January, 2043. PSE&G also has $300 million of 5.38% Medium Term Notes maturing in September 2013 and $275 million of 6.33% Medium Term Notes maturing in November 2013. Power has $300 million of 2.50% Senior Notes maturing in April 2013.

For a discussion of our long-term debt transactions during 2012 and into 2013, 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 to 1, and/or against retired Mortgage Bonds. As of December 31, 2012, PSE&G’s Mortgage coverage ratio was 3.6 to 1 and the Mortgage would permit up to approximately $2.6 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.

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Common Stock Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	2012	2011	2010
Per Share	$1.42	$1.37	$1.37
in Millions	$718	$693	$693

In 2012, dividend payments increased from $1.37 per share to $1.42 per share, representing a change in our dividend policy, moving from a strict earnings payout based approach to one that takes into consideration the growing contribution to earnings and cash from our regulated operations and continued cash flow from our generation business.

On February 19, 2013, our Board of Directors approved a $0.36 per share common stock dividend for the first quarter of 2013. This reflects an indicated annual dividend rate of $1.44 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 May 2012, Moody's published updated credit opinions on PSEG, Power and PSE&G. Moody's upgraded PSE&G's Mortgage Bond Rating to A1 from A2 and revised the outlook to stable from positive. PSEG's and Power's ratings and outlooks remained unchanged. In October 2012, S&P published updated credit opinions that left the ratings and outlooks for Power and PSE&G unchanged. In November 2012, S&P published an updated credit opinion for PSEG that left its ratings and outlook unchanged. In July 2012, Fitch upgraded PSE&G's Mortgage Bond Rating to A+ from A and its stable outlook remained unchanged. In January 2013, Fitch published updated credit opinions on PSEG, Power and PSE&G. PSEG's, Power's and PSE&G's ratings and outlooks remained unchanged.

	Moody’s (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	Stable	Positive	Stable
Commercial Paper	P2	A2	F2
Power			
Outlook	Stable	Positive	Stable
Senior Notes	Baa1	BBB	BBB+
PSE&G			
Outlook	Stable	Positive	Stable
Mortgage Bonds	A1	A-	A+
Commercial Paper	P2	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.

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Other Comprehensive Loss

For the year ended December 31, 2012, we had Other Comprehensive Loss of $51 million on a consolidated basis. Other Comprehensive Loss was due primarily to a $46 million increase in our consolidated liability for pension and postretirement benefits and $24 million of unrealized losses on derivative contracts accounted for as hedges and was partially offset by $19 million of net unrealized gains related to Available-for-Sale Securities.

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.

	2013	2014	2015
Power:		Millions	
Baseline Maintenance	$215	$170	$200
Environmental/Regulatory	70	70	15
Nuclear Expansion	115	125	90
Total Power	$400	$365	$305
PSE&G:			
Transmission			
Reliability Enhancements	$1,230	$1,040	$550
Facility Replacement	265	145	160
Support Facilities	10	15	10
Environmental/Regulatory	5	—	—
Distribution			
Reliability Enhancements	85	75	75
Facility Replacement	140	150	175
Support Facilities	45	50	45
New Business	125	130	135
Environmental/Regulatory	35	35	30
Renewables	100	40	—
Total PSE&G	$2,040	$1,680	$1,180
Non-Utility Renewables	50	—	—
Other	45	40	30
Total PSEG	$2,535	$2,085	$1,515

Power

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

- Baseline Maintenance—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Nuclear Expansion—investments associated with various capital projects at existing facilities to either extend plants’ useful lives or increase operating output.

In 2012, Power made $438 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $208 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear.

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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 improve 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 2012, PSE&G made $1,852 million of capital expenditures, including $1,770 million of investment in plant, primarily for transmission and distribution system reliability and $82 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 $116 million, which are included in operating cash flows.

Additional Projects

The estimated project expenditures related to the following filings or transmission infrastructure investments are not included in our $6.1 billion three-year capital forecast table.

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 harden and 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. We also intend to invest $1.5 billion in FERC jurisdictional investments in transmission infrastructure over the next ten years.

In July 2012, we filed for an extension of our Solar 4 All program. In this filing, we are seeking BPU approval for up to $690 million to develop 136 MW of utility-owned solar photovoltaic systems over a five year period starting in 2013. Consistent with the existing Solar 4 All program, we propose to sell the energy and capacity from the solar systems in the PJM wholesale energy and capacity markets which will offset the cost of the program.

We also filed for an additional extension of our Solar Loan program (Solar Loan III) in July 2012. In the filing, we are seeking BPU approval to provide financing support for the installation of 97.5 MW of solar systems by providing loans to qualified customers. The total investment of the proposed Solar Loan III program is anticipated to be up to $193 million once the program is fully subscribed, projects are built and loans are closed.

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. See Item 8. Financial Statements and Supplementary Data -Note 13. Commitments and Contingent Liabilities for a discussion of contractual commitments related to the construction activity, discussed above, and for a variety of services for which annual amounts are not quantifiable. 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.

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	Total Amount Committed Millions	Less Than 1 Year	2 - 3 Years	4- 5 Years	Over 5 Years
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
Power	$2,353	$300	$344	$553	$1,156
PSE&G	4,804	725	800	171	3,108
Transition Funding (PSE&G)	690	214	476	—	—
Transition Funding II (PSE&G)	32	12	20	—	—
Long-Term Non-Recourse Project Financing					
Energy Holdings	44	1	18	8	17
Interest on Recourse Debt					
Power	1,194	118	228	172	676
PSE&G	3,370	224	356	314	2,476
Transition Funding (PSE&G)	80	42	38	—	—
Transition Funding II (PSE&G)	2	1	1	—	—
Interest on Non-Recourse Project Financing					
Energy Holdings	12	2	4	3	3
Capital Lease Obligations					
PSEG	20	7	13	—	—
Power	5	2	3	—	—
Operating Leases					
PSEG	214	—	3	25	186
Power	8	—	2	2	4
PSE&G	54	7	9	6	32
Energy Holdings	21	2	4	3	12
Energy-Related Purchase Commitments					
Power	2,796	667	1,133	811	185
Total Contractual Cash Obligations	$15,699	$2,324	$3,452	$2,068	$7,855
Commercial Commitments					
Standby Letters of Credit					
Power	$214	$169	$45	$—	$—
PSE&G	13	13	—	—	—
Guarantees and Equity Commitments					
Energy Holdings	53	53	—	—	—
Total Commercial Commitments	$280	$235	$45	$—	$—
Liability Payments for Uncertain Tax Positions					
PSEG	$—	$—	$—	$—	$—
Power	5	5	—	—	—
PSE&G	—	—	—	—	—
Energy Holdings	70	70	—	—	—

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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.

Energy Holdings

We have certain investments that are accounted for under the equity method in accordance with GAAP. Accordingly, amounts recorded on the Consolidated Balance Sheets for such investments represent our equity investment, which is increased for our pro-rata share of earnings less any dividend distribution from such investments. One of the companies in which we invest that is accounted for under the equity method has an aggregate $28 million of long-term debt on its Consolidated Balance Sheet. Our pro-rata share of such debt is $14 million. This debt is non-recourse to us. We are generally not required to support the debt service obligations of this company. However, default with respect to this non-recourse debt could result in a loss of invested equity.

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 collectability 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

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	2012		2011		2010	
Discount Rate	4.20	%	5.00	%	5.51	%
Rate of Return on Plan Assets	8.00	%	8.50	%	8.50	%

Our discount rate assumption, which is determined annually, is based on the rates of return on high-quality fixed-income investments currently available and expected to be available during the period to maturity of the pension benefits. 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.

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.

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Based on the above assumptions, we have estimated net periodic pension expense of approximately $110 million, net of amounts capitalized, and contributions of up to $145 million in 2013.

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 4.20% discount rate for 2013, a 4.50% discount rate for 2014, increasing annually by 25 basis points to 5.25% in 2017. Actual future pension expense 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, 2012	Increase to Pension Expense in 2013
		Millions	
Discount Rate	(1)%	$751	$72
Rate of Return on Plan Assets	(1)%	$—	$44

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.

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

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Lease Investments

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

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

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses, 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 $177 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:

- 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 94% of Power’s total AROs as of December 31, 2012. 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 used at December 31, 2012 would result in a $134 million increase in the Nuclear ARO as of December 31, 2012. A 1% increase in the inflation rate used at December 31, 2012 would result in a $335 million increase in the Nuclear ARO as of December 31, 2012. 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 $273 million at December 31, 2012.

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.

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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, Superstorm Sandy caused severe damage to our transmission and distribution system as well as to some of our generation infrastructure in the northern part of New Jersey. Strong winds resulted in a storm surge that caused damage to switching stations, substations and generating infrastructure. We are in the early stages of gathering information needed in preparing an insurance claim relating to that damage. As of December 31, 2012, we recorded estimated insurance proceeds of $25 million ($19 million for Power and $6 million for PSE&G). See Item 8. Financial Statements and Supplementary Data—Note 13. Commitments and Contingencies for additional information.

Assumptions and Approach Used: In December 2012, we received correspondence from representatives of the various insurance carriers acknowledging that damages were sustained and authorizing $25 million in advance payments to be made to us. Based on that authorization, we recorded the estimated insurance proceeds of $25 million. We believe that any further proceeds to be received under our policies are not estimable at December 31, 2012. We are at the early stages of documenting our insurance claim which then needs to be submitted to, and reviewed by, the insurers. We believe we have no basis for developing an estimate for any further insurance recoveries at this time.

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.

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Year Ended December 31, 2012	MTM VaR (A) Millions
95% Confidence Level, Loss could exceed VaR one day in 20 days	
Period End	$18
Average for the Period	$16
High	$29
Low	$7
99.5% Confidence Level, Loss could exceed VaR one day in 200 days	
Period End	$28
Average for the Period	$25
High	$46
Low	$11

(A) As of December 31, 2012 and December 31, 2011, there was no trading VaR since we discontinued trading activities in the second quarter of 2011.

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, 2012, 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 $223 million decrease in the fair value of debt, including a $56 million decrease at Power and a $166 million decrease at PSE&G.

Debt and Equity Securities

We have $4.6 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,
- 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 $1.5 billion as of December 31, 2012. As of December 31, 2012, the portfolio includes $789 million of equity securities and $627 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, 2012, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $79 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 4.31 years and a yield of 1.24%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2012, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $27 million.

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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 with respect to its counterparties to power purchase agreements and other parties. Energy Holdings also has credit risk related to its investments in leases, which totaled $117 million, net of deferred taxes of $723 million, as of December 31, 2012. 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.

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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, 2012 and 2011, 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, 2012. 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 audits 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, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2013

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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, 2012 and 2011, 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, 2012. 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 audits 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, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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 25, 2013

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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, 2012 and 2011, 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, 2012. 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 audits 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 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, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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 25, 2013

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2012	2011	2010
OPERATING REVENUES	$9,781	$11,079	$11,793
OPERATING EXPENSES			
Energy Costs	3,719	4,747	5,261
Operation and Maintenance	2,632	2,481	2,504
Depreciation and Amortization	1,054	976	955
Taxes Other Than Income Taxes	98	133	136
Total Operating Expenses	7,503	8,337	8,856
OPERATING INCOME	2,278	2,742	2,937
Income from Equity Method Investments	12	4	4
Other Income	260	220	221
Other Deductions	(98)	(85)	(63)
Other-Than-Temporary Impairments	(18)	(22)	(11)
Interest Expense	(423)	(475)	(472)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,011	2,384	2,616
Income Tax (Expense) Benefit	(736)	(977)	(1,059)
INCOME FROM CONTINUING OPERATIONS	1,275	1,407	1,557
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $0, $(51) and $(8) for the years ended 2012, 2011 and 2010, respectively	—	96	7
NET INCOME	$1,275	$1,503	$1,564
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):			
BASIC	505,933	505,949	505,985
DILUTED	507,086	506,982	507,045
EARNINGS PER SHARE:			
BASIC			
INCOME FROM CONTINUING OPERATIONS	$2.52	$2.78	$3.08
NET INCOME	$2.52	$2.97	$3.09
DILUTED			
INCOME FROM CONTINUING OPERATIONS	$2.51	$2.77	$3.07
NET INCOME	$2.51	$2.96	$3.08
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$1.42	$1.37	$1.37

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2012	2011	2010
NET INCOME	$1,275	$1,503	$1,564
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(24), $43 and $(12) for the years ended 2012, 2011 and 2010, respectively	19	(39)	6
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $(11), $(33) and $(42) for the years ended 2012, 2011 and 2010, respectively	17	47	60
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $29, $87 and $90 for the years ended 2012, 2011 and 2010, respectively	(41)	(127)	(129)
Pension/OPEB adjustment, net of tax (expense) benefit of $32, $44 and $(18) for the years ended 2012, 2011 and 2010, respectively	(46)	(62)	23
Other Comprehensive Income (Loss), net of tax	(51)	(181)	(40)
COMPREHENSIVE INCOME	$1,224	$1,322	$1,524

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$379	$834
Accounts Receivable, net of allowances of $56 and $56 in 2012 and 2011, respectively	1,069	967
Tax Receivable	227	16
Unbilled Revenues	314	289
Fuel	583	685
Materials and Supplies, net	422	367
Prepayments	283	308
Derivative Contracts	138	156
Deferred Income Taxes	49	—
Regulatory Assets	349	167
Other	56	122
Total Current Assets	3,869	3,911
PROPERTY, PLANT AND EQUIPMENT	27,402	25,080
Less: Accumulated Depreciation and Amortization	(7,666)	(7,231)
Net Property, Plant and Equipment	19,736	17,849
NONCURRENT ASSETS		
Regulatory Assets	3,830	3,805
Regulatory Assets of Variable Interest Entities (VIEs)	713	925
Long-Term Investments	1,324	1,303
Nuclear Decommissioning Trust (NDT) Fund	1,540	1,349
Other Special Funds	191	172
Goodwill	16	16
Other Intangibles	34	131
Derivative Contracts	153	106
Restricted Cash of VIEs	23	22
Other	296	232
Total Noncurrent Assets	8,120	8,061
TOTAL ASSETS	$31,725	$29,821

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	2011
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year (includes $50 at fair value in 2011)	$1,026	$417
Securitization Debt of VIEs Due Within One Year	226	216
Commercial Paper and Loans	263	—
Accounts Payable	1,304	1,184
Derivative Contracts	46	131
Accrued Interest	91	97
Accrued Taxes	17	30
Deferred Income Taxes	72	170
Clean Energy Program	153	214
Obligation to Return Cash Collateral	122	107
Regulatory Liabilities	67	100
Other	390	291
Total Current Liabilities	3,777	2,957
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	6,542	5,458
Regulatory Liabilities	209	228
Regulatory Liabilities of VIEs	10	9
Asset Retirement Obligations	627	489
Other Postretirement Benefit (OPEB) Costs	1,285	1,127
Accrued Pension Costs	876	734
Clean Energy Program	—	39
Environmental Costs	537	643
Derivative Contracts	122	26
Long-Term Accrued Taxes	164	292
Other	108	86
Total Noncurrent Liabilities	10,480	9,131
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,148	6,694
Securitization Debt of VIEs	496	723
Project Level, Non-Recourse Debt	43	44
Total Long-Term Debt	6,687	7,461
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2012 and 2011—533,556,660 shares	4,833	4,823
Treasury Stock, at cost, 2012—27,664,188 shares; 2011—27,611,374 shares	(607)	(601)
Retained Earnings	6,942	6,385
Accumulated Other Comprehensive Loss	(388)	(337)

Total Common Stockholders' Equity	10,780	10,270
Noncontrolling Interest	1	2
Total Stockholders' Equity	10,781	10,272
Total Capitalization	17,468	17,733
TOTAL LIABILITIES AND CAPITALIZATION	$31,725	$29,821

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$1,275	$1,503	$1,564
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	—	(122)	—
Depreciation and Amortization	1,054	982	974
Amortization of Nuclear Fuel	173	153	136
Provision for Deferred Income Taxes (Other than Leases) and ITC	721	811	1,106
Non-Cash Employee Benefit Plan Costs	271	175	315
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	93	(55)	(336)
Loss on Leases, net of tax	—	170	—
Net (Gain) Loss on Lease Investments	(49)	(55)	(56)
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	63	(165)	50
Deferred Storm Costs	(90)	(60)	(8)
Net Change in Regulatory Assets and Liabilities	(132)	(130)	(58)
Cost of Removal	(116)	(62)	(58)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(118)	(117)	(106)
Net Change in Tax Receivable	(211)	673	(689)
Net Change in Certain Current Assets and Liabilities	97	247	(221)
Employee Benefit Plan Funding and Related Payments	(314)	(508)	(508)
Other	70	117	59
Net Cash Provided By (Used In) Operating Activities	2,787	3,557	2,164
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,574)	(2,083)	(2,160)
Proceeds from Sale of Discontinued Operations	—	687	—
Proceeds from Sale of Capital Leases and Investments	58	179	496
Proceeds from Sales of Available-for-Sale Securities	1,666	1,355	1,116
Investments in Available-for-Sale Securities	(1,700)	(1,386)	(1,140)
Other	(75)	(21)	19
Net Cash Provided By (Used In) Investing Activities	(2,625)	(1,269)	(1,669)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	263	(64)	(466)
Issuance of Long-Term Debt	900	794	1,728
Redemption of Long-Term Debt, including Securitization Debt	(1,003)	(1,720)	(972)
Repayment of Non-Recourse Debt	(1)	(1)	(32)
Cash Dividend Paid on Common Stock	(718)	(693)	(693)
Redemption of Preferred Securities	—	—	(80)
Other	(58)	(50)	(50)
Net Cash Provided By (Used In) Financing Activities	(617)	(1,734)	(565)
Net Increase (Decrease) in Cash and Cash Equivalents	(455)	554	(70)
Cash and Cash Equivalents at Beginning of Period	834	280	350

Cash and Cash Equivalents at End of Period	$379	$834	$280
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$121	$(219)	$1,070
Interest Paid, Net of Amounts Capitalized	$402	$479	$444
Accrued Property, Plant and Equipment Expenditures	$370	$336	$235

See the Notes to Consolidated Financial Statements.

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

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
	Shs.	Amount	Shs.	Amount				
Balance as of January 1, 2010	534	$4,788	(28)	$(588)	$4,704	$(116)	$10	$8,798
Net Income	—	—	—	—	1,564	—	—	1,564
Other Comprehensive Income (Loss), net of tax (expense) benefit of $18	—	—	—	—	—	(40)	—	(40)
Comprehensive Income								1,524
Cash Dividends on Common Stock	—	—	—	—	(693)	—	—	(693)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(2)	(2)
Other	—	19	—	(5)	—	—	—	14
Balance as of December 31, 2010	534	$4,807	(28)	$(593)	$5,575	$(156)	$8	$9,641
Net Income	—	—	—	—	1,503	—	—	1,503
Other Comprehensive Income (Loss), net of tax (expense) benefit of $141	—	—	—	—	—	(181)	—	(181)
Comprehensive Income								1,322
Cash Dividends on Common Stock	—	—	—	—	(693)	—	—	(693)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(6)	(6)
Other	—	16	—	(8)	—	—	—	8
Balance as of December 31, 2011	534	$4,823	(28)	$(601)	$6,385	$(337)	$2	$10,272
Net Income	—	—	—	—	1,275	—	—	1,275
Other Comprehensive Income (Loss), net of tax (expense) benefit of $26	—	—	—	—	—	(51)	—	(51)
Comprehensive Income								1,224
Cash Dividends on Common Stock	—	—	—	—	(718)	—	—	(718)
Noncontrolling Interest in Losses of Consolidated Entity	—	—	—	—	—	—	(1)	(1)
Other	—	10	—	(6)	—	—	—	4

Balance as of December 31, 2012	534	$4,833	(28	)	$(607	)	$6,942	$(388	)	$1	$10,781

See Notes to Consolidated Financial Statements.

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2012	2011	2010
OPERATING REVENUES	$4,865	$6,143	$6,558
OPERATING EXPENSES			
Energy Costs	2,383	3,046	3,374
Operation and Maintenance	1,122	1,102	1,046
Depreciation and Amortization	237	224	175
Total Operating Expenses	3,742	4,372	4,595
OPERATING INCOME	1,123	1,771	1,963
Other Income	199	190	170
Other Deductions	(90)	(79)	(53)
Other-Than-Temporary Impairments	(18)	(20)	(9)
Interest Expense	(134)	(175)	(157)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	1,080	1,687	1,914
Income Tax (Expense) Benefit	(433)	(685)	(778)
INCOME FROM CONTINUING OPERATIONS	647	1,002	1,136
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $0, $(51) and $(8) for the years ended 2012, 2011 and 2010, respectively	—	96	7
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$647	$1,098	$1,143

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2012	2011	2010
NET INCOME	$647	$1,098	$1,143
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $(24), $45 and $(17) for the years ended 2012, 2011 and 2010, respectively	18	(42)	15
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $(11), $(33) and $(42) for the years ended 2012, 2011 and 2010, respectively	17	47	60
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $29, $87, and $90 for the years ended 2012, 2011 and 2010, respectively	(41)	(127)	(129)
Pension/OPEB adjustment, net of tax (expense) benefit of $32, $40, and $(15) for the years ended 2012, 2011 and 2010, respectively	(46)	(59)	21
Other, net of tax (expense) benefit of $0 for the year ended 2010	—	—	(1)
Other Comprehensive Income (Loss), net of tax	(52)	(181)	(34)
COMPREHENSIVE INCOME	$595	$917	$1,109

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

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$7	$12
Accounts Receivable	269	267
Accounts Receivable—Affiliated Companies, net	340	381
Short-Term Loan to Affiliate	574	907
Fuel	583	685
Materials and Supplies, net	307	272
Derivative Contracts	118	139
Prepayments	17	24
Other	19	—
Total Current Assets	2,234	2,687
PROPERTY, PLANT AND EQUIPMENT	9,697	9,191
Less: Accumulated Depreciation and Amortization	(2,679)	(2,460)
Net Property, Plant and Equipment	7,018	6,731
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,540	1,349
Goodwill	16	16
Other Intangibles	34	131
Other Special Funds	36	33
Derivative Contracts	49	55
Other	105	85
Total Noncurrent Assets	1,780	1,669
TOTAL ASSETS	$11,032	$11,087

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

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	2011
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$300	$66
Accounts Payable	498	541
Derivative Contracts	46	124
Deferred Income Taxes	16	53
Accrued Interest	26	32
Other	81	86
Total Current Liabilities	967	902
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,575	1,266
Asset Retirement Obligations	369	259
Other Postretirement Benefit (OPEB) Costs	221	180
Derivative Contracts	15	24
Accrued Pension Costs	272	236
Long-Term Accrued Taxes	50	8
Other	84	83
Total Noncurrent Liabilities	2,586	2,056
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
LONG-TERM DEBT		
Total Long-Term Debt	2,040	2,685
MEMBER'S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,725	4,678
Accumulated Other Comprehensive Loss	(328)	(276)
Total Member's Equity	5,439	5,444
TOTAL LIABILITIES AND MEMBER'S EQUITY	$11,032	$11,087

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

PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$647	$1,098	$1,143
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Gain on Disposal of Discontinued Operations	—	(122)	—
Depreciation and Amortization	237	231	194
Amortization of Nuclear Fuel	173	153	136
Provision for Deferred Income Taxes and ITC	342	231	650
Interest Accretion on Asset Retirement Obligation	21	18	18
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	63	(165)	50
Non-Cash Employee Benefit Plan Costs	70	41	71
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(118)	(117)	(106)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	47	(26)	135
Margin Deposit	(116)	49	(91)
Accounts Receivable	24	197	(105)
Accounts Payable	92	(154)	17
Accounts Receivable/Payable-Affiliated Companies, net	(40)	459	(386)
Accrued Interest Payable	(6)	(8)	(3)
Other Current Assets and Liabilities	(16)	38	(63)
Employee Benefit Plan Funding and Related Payments	(72)	(129)	(132)
Other	31	18	38
Net Cash Provided By (Used In) Operating Activities	1,379	1,812	1,566
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(646)	(757)	(825)
Proceeds from Sale of Discontinued Operations	—	687	—
Proceeds from Sales of Available-for-Sale Securities	1,478	1,355	989
Investments in Available-for-Sale Securities	(1,506)	(1,380)	(1,013)
Short-Term Loan—Affiliated Company, net	333	(509)	(398)
Other	(7)	26	42
Net Cash Provided By (Used In) Investing Activities	(348)	(578)	(1,205)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Recourse Long-Term Debt	—	544	594
Cash Dividend Paid	(600)	(500)	(549)
Redemption of Long-Term Debt	(414)	(1,250)	(248)
Short-Term Loan—Affiliated Company, net	—	—	(194)
Cash Payment on Debt Redemption/Exchange	(15)	(17)	(13)
Other	(7)	(10)	(4)
Net Cash Provided By (Used In) Financing Activities	(1,036)	(1,233)	(414)
Net Increase (Decrease) in Cash and Cash Equivalents	(5)	1	(53)
Cash and Cash Equivalents at Beginning of Period	12	11	64

Cash and Cash Equivalents at End of Period	$7	$12	$11
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$136	$171	$539
Interest Paid, Net of Amounts Capitalized	$119	$176	$151
Accrued Property, Plant and Equipment Expenditures	$95	$132	$111

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER'S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2010	$2,028	$(986)	$3,486	$(61)	$4,467
Net Income	—	—	1,143	—	1,143
Other Comprehensive Income (Loss), net of tax (expense) benefit of $16	—	—	—	(34)	(34)
Comprehensive Income					1,109
Cash Dividends Paid	—	—	(549)	—	(549)
Balance as of December 31, 2010	$2,028	$(986)	$4,080	$(95)	$5,027
Net Income	—	—	1,098	—	1,098
Other Comprehensive Income (Loss), net of tax (expense) benefit of $139	—	—	—	(181)	(181)
Comprehensive Income					917
Cash Dividends Paid	—	—	(500)	—	(500)
Balance as of December 31, 2011	$2,028	$(986)	$4,678	$(276)	$5,444
Net Income	—	—	647	—	647
Other Comprehensive Income (Loss), net of tax (expense) benefit of $26	—	—	—	(52)	(52)
Comprehensive Income					595
Cash Dividends Paid	—	—	(600)	—	(600)
Balance as of December 31, 2012	$2,028	$(986)	$4,725	$(328)	$5,439

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2012	2011	2010
OPERATING REVENUES	$6,626	$7,326	$7,869
OPERATING EXPENSES			
Energy Costs	3,159	3,951	4,655
Operation and Maintenance	1,508	1,372	1,442
Depreciation and Amortization	778	719	750
Taxes Other Than Income Taxes	98	133	136
Total Operating Expenses	5,543	6,175	6,983
OPERATING INCOME	1,083	1,151	886
Other Income	52	25	26
Other Deductions	(5)	(4)	(3)
Other-Than-Temporary Impairments	—	(1)	—
Interest Expense	(295)	(310)	(318)
INCOME BEFORE INCOME TAXES	835	861	591
Income Tax (Expense) Benefit	(307)	(340)	(232)
NET INCOME	528	521	359
Preferred Stock Dividends	—	—	(1)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$528	$521	$358

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

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

	Years Ended December 31,		
	2012	2011	2010
NET INCOME	$528	$521	$359
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $(1) and $3 for the years ended 2012, 2011 and 2010, respectively	—	2	(5)
COMPREHENSIVE INCOME	$528	$523	$354

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$116	$143
Accounts Receivable, net of allowances of $56 and $56 in 2012 and 2011, respectively	783	691
Tax Receivable	—	16
Unbilled Revenues	314	289
Materials and Supplies	114	94
Prepayments	29	117
Regulatory Assets	349	167
Derivative Contracts	5	—
Deferred Income Taxes	49	—
Other	24	21
Total Current Assets	1,783	1,538
PROPERTY, PLANT AND EQUIPMENT	17,006	15,306
Less: Accumulated Depreciation and Amortization	(4,726)	(4,539)
Net Property, Plant and Equipment	12,280	10,767
NONCURRENT ASSETS		
Regulatory Assets	3,830	3,805
Regulatory Assets of VIEs	713	925
Long-Term Investments	348	280
Other Special Funds	61	57
Derivative Contracts	62	4
Restricted Cash of VIEs	23	22
Other	123	89
Total Noncurrent Assets	5,160	5,182
TOTAL ASSETS	$19,223	$17,487

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2012	2011
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$725	$300
Securitization Debt of VIEs Due Within One Year	226	216
Commercial Paper and Loans	263	—
Accounts Payable	630	498
Accounts Payable—Affiliated Companies, net	73	280
Accrued Interest	65	65
Clean Energy Program	153	214
Derivative Contracts	—	7
Deferred Income Taxes	60	32
Obligation to Return Cash Collateral	122	107
Regulatory Liabilities	67	100
Other	269	186
Total Current Liabilities	2,653	2,005
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	4,223	3,675
Other Postretirement Benefit (OPEB) Costs	1,011	900
Accrued Pension Costs	463	355
Regulatory Liabilities	209	228
Regulatory Liabilities of VIEs	10	9
Clean Energy Program	—	39
Environmental Costs	486	592
Asset Retirement Obligations	250	226
Derivative Contracts	107	—
Long-Term Accrued Taxes	32	83
Other	38	35
Total Noncurrent Liabilities	6,829	6,142
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 13)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	4,070	3,970
Securitization Debt of VIEs	496	723
Total Long-Term Debt	4,566	4,693
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2012 and 2011—132,450,344 shares	892	892
Contributed Capital	420	420
Basis Adjustment	986	986
Retained Earnings	2,875	2,347
Accumulated Other Comprehensive Income	2	2

Total Stockholder’s Equity	5,175	4,647
Total Capitalization	9,741	9,340
TOTAL LIABILITIES AND CAPITALIZATION	$19,223	$17,487

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

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

	Years Ended December 31,		
	2012	2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$528	$521	$359
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	778	719	750
Provision for Deferred Income Taxes and ITC	442	571	444
Non-Cash Employee Benefit Plan Costs	179	118	217
Cost of Removal	(116)	(62)	(58)
Deferred Storm Costs	(90)	(60)	(8)
Net Change in Regulatory Assets and Liabilities	(132)	(130)	(58)
Net Change in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	(54)	252	(21)
Materials and Supplies	(20)	(4)	(20)
Prepayments	88	—	(31)
Net Change in Tax Receivable	16	(16)	—
Accounts Receivable/Payable-Affiliated Companies, net	(132)	197	(286)
Other Current Assets and Liabilities	12	(40)	68
Employee Benefit Plan Funding and Related Payments	(213)	(330)	(327)
Other	(30)	40	(18)
Net Cash Provided By (Used In) Operating Activities	1,256	1,776	1,011
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,770)	(1,302)	(1,257)
Proceeds from Sales of Available-for-Sale Securities	77	—	54
Investments in Available-for-Sale Securities	(77)	—	(54)
Solar Loan Investments	(74)	(51)	(27)
Other	(1)	(1)	4
Net Cash Provided By (Used In) Investing Activities	(1,845)	(1,354)	(1,280)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	263	—	—
Issuance of Long-Term Debt	900	250	1,114
Redemption of Long-Term Debt	(373)	(264)	(400)
Redemption of Securitization Debt	(216)	(206)	(197)
Redemption of Preferred Securities	—	—	(80)
Cash Dividend Paid	—	(300	