PUBLIC SERVICE ELECTRIC & GAS CO
Form 10-K
February 25, 2010
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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, 2009,

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	22-3663480

http://www.pseg.com

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	New York Stock Exchange
	6 3/4% Series VV, due 2016	
	8%, due 2037	
	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, Series A, B, C, D, E, F and G

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).

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

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See 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 ¨	Smaller reporting company ¨
PSEG Power LLC	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x	Smaller reporting company ¨
Public Service Electric and Gas Company	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x	Smaller reporting company ¨

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, 2009 was $16,495,708,079 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 29, 2010 was 505,952,069.

As of January 29, 2010, 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 2010 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, 2010, 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, hypothetical, potential, forecast, 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 12. 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 energy industry law, policies and regulation, including market structures and rules 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 operations of our generating units,
- changes in nuclear regulation and/or developments in the nuclear power industry generally 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 trading risks,
- any deterioration in our credit quality,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- any inability to realize anticipated tax benefits or retain tax credits,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays or unforeseen cost escalations in our construction and development activities,

- increase in competition in energy markets in which we compete,

- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in discount rates and funding requirements, and

- changes in technology and increased customer conservation.

Additional information concerning these factors are set forth under Item 1A. Risk Factors.

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 only apply 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 201.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and special reports, proxy statements and other information with the U.S. Securities and Exchange Commission (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 contained 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, 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 wholly owned subsidiary, provides us and these operating subsidiaries with certain management, administrative and general services at cost.

As of and for the Year Ended December 31, 2009

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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 principal 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, energy trading and marketing and risk management 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 company which was incorporated 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 customers throughout its service territory.	Earns revenues from managing leveraged lease investments and the operation of its domestic generation projects.
		Also pursuing solar and other renewable generation projects.
	It is implementing several programs to improve efficiencies in customer energy use and increase the level of renewable generation.	

The majority of our earnings are derived from the operations of Power, which has contributed at least 70% of our Income from Continuing Operations over the past three years. While this part of the business has produced significant earnings over that period, its operations are subject to higher risks resulting from volatility in the energy markets. As a rate-regulated public utility, PSE&G has continued to be a stable earnings contributor for us. Earnings from Energy Holdings have significantly declined over the past few years as we sold virtually all of our investments in international projects. Energy Holdings earnings have also been impacted by gains and losses on its asset sales and other charges and impairments taken on its remaining investments.

Earnings (Losses) in millions	**2009**	**2008**	**2007**
Power	$ 1,189	$ 1,115	$ 1,000
PSE&G	325	364	380
Energy Holdings	72	(468)	12
Other	6	(28)	(67)
PSEG Income from Continuing Operations	**$ 1,592**	**$ 983**	**$ 1,325**

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

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BUSINESSOPERATIONS AND STRATEGY

Power

Through Power, we seek to produce low-cost energy by efficiently operating our nuclear, coal and gas-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 kWh or dollars per 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 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. The current BGSS contract runs through March 31, 2012.

About 44% of PSE&G s peak daily gas requirements comes from Power s firm transportation, which is available every day of the year. Power satisfies the remainder of PSE&G s requirements from field storage, liquefied natural gas, seasonal purchases, contract peaking supply, propane, refinery and landfill gas. Based upon availability, Power also sells gas to others.

How Power Operates

We own approximately 13,500 MWs of generation capacity located in the Northeast and Mid Atlantic regions of the U.S. in some of the country s largest and most developed electricity markets.

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The map below shows the locations of Power s Northeast and Mid Atlantic generation facilities.

We also own 2,000 MW of generation capacity in Texas which was transferred from Energy Holdings in October 2009. See Item 8. Financial Statements and Supplementary Data Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies for additional information.

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

Generation Capacity

Our installed capacity utilizes a diverse mix of fuels: 52% gas, 24% nuclear, 15% 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 2009 was approximately 59,800 GWh. The following table indicates the proportionate share of generating output by fuel type.

Generation by Fuel Type	Actual 2009
Nuclear:	
New Jersey facilities	35%
Pennsylvania facilities	16%
Fossil:	
Coal:	
New Jersey facilities	5%
Pennsylvania facilities	8%
Connecticut facilities	2%
Oil and Natural Gas:	
New Jersey facilities	15%
New York facilities	6%
Texas facilities	13%
Total	**100%**

The generation by our coal units in 2009 was adversely affected by 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. This caused a decrease in our coal unit production in 2009 compared to 2008. We expect our coal unit generation to increase in 2010 as compared to 2009.

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 31% base load, 50% load following and 19% 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** 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. Our base load nuclear unit capacity factors were as follows:

Unit	Capacity Factor

Salem Unit 1	99.1%
Salem Unit 2	92.0%
Hope Creek	91.2%
Peach Bottom Unit 2	99.3%
Peach Bottom Unit 3	86.9%

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

- **Load Following Units** 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 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 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. The following chart depicts the merit order of dispatch in PJM, where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that recent market price fluctuations have resulted in changes from historical norms, with lower gas prices allowing some gas generation to displace some coal generation:

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 locational marginal pricing (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.

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

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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 LMP in congested areas, reflecting the bid prices of those higher-cost generation units.

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 graphs below which present historical annual spot prices and forward calendar prices as averaged over each year.

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 Power operates.

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 is no assurance that such prices will remain in effect nor that we will be able to contract output at these forward prices.

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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.

Coal Supply Coal is the primary fuel for our Hudson, Mercer, Keystone, Conemaugh and Bridgeport stations. We have 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 and Hudson 2 units use a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources were not available for these facilities, their near-term operations would be adversely impacted. In the longer-term, 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. We anticipate completing the installation of pollution control equipment by the end of 2010 at our Hudson unit which will provide more flexibility in the types of coal we can use at that station.

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 three firm gas transportation contracts to serve both of our Texas plants and have recently contracted for a firm transportation service for our Bethlehem Energy Center (BEC) in New York.

We have 1.2 billion cubic feet-per-day of firm transportation capacity under contract to meet the primary gas supply needs of our generation fleet and our obligations under the BGSS contract. We supplement that supply with a total storage capacity of 78 billion cubic feet.

Oil Oil is used as the primary fuel for two load following steam units 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. MD&A Overview of 2009 and Future Outlook and Note 12. Commitments and Contingent Liabilities.

Markets and Market Pricing

Power s assets are located in four centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of FERC or, in the case of ERCOT, the Texas Public Utility Commission:

PJM Regional Transmission Organization PJM conducts the largest centrally dispatched energy market in North America. It serves over 51 million people, nearly 17% of the total U.S. population and a peak demand of over 144,000 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. All of Power s generating stations operate in PJM, except for the BEC, Guadalupe, Odessa, Bridgeport and New Haven stations**.**

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New York The NY ISO is the market coordinator for New York State and is now 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 33,900 MW. Power s 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 28,000 MW. Power s Bridgeport and New Haven stations operate in Connecticut.

Texas The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to Texas customers representing 85 percent of the state s electric load and 75 percent of the Texas land area. The ERCOT service area has a population of about 22 million and a peak demand of over 63,400 MW. As the ISO for the region, ERCOT schedules power on the electric grid. Power s Guadalupe and Odessa plants operate in ERCOT.

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 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.

Since the majority of the power we generate has generally been sourced from lower-cost nuclear and coal units, the rise in electric prices in recent years has yielded higher margins for us. Over a longer-term horizon, 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 risk should any of our generating units fail to function effectively or otherwise become unavailable.

In addition to energy sales, we also earn revenue from capacity payments for our assets in the Northeast and Mid-Atlantic U.S. These payments are compensation for committing that a portion of our capacity be available 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. Previously, some generators, including us, announced the retirement or potential retirement of certain older generating facilities due to insufficient revenues to support their continued operation. To enable the continued availability of these facilities, in separate instances, both PJM and ISO-NE agreed to enter into Reliability-Must-Run (RMR) arrangements to compensate us for those units contribution to reliability.

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 clarity 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.

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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 2008 to May 2009	$ 148.80	$ 54.31
June 2009 to May 2010	$ 191.32	$ 69.83
June 2010 to May 2011	$ 174.29	$ 63.62
June 2011 to May 2012	$ 110.00	$ 40.16
June 2012 to May 2013	$ 139.73	$ 51.70

The zone in which our Keystone and Conemaugh units are located has experienced fewer constraints on its transmission system, and we have received prices lower than the prices for the rest of our PJM generating assets for periods through May of 2010. This is not the case for the periods from June 2010 to May 2012 when identical prices were set for all zones. However, the most recent auction, for the 2012-2013 delivery year, once again resulted in differing prices for various areas of PJM, with Keystone and Conemaugh receiving lower prices than the majority of our PJM generating units and our generating units in northern New Jersey receiving 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 these 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 will 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 outage rates, etc.);
- increases in transmission capability between zones; and
- 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 may propose over time.

For additional information on our collection of RMR payments in PJM and ISO-NE and the RPM and FCM proposals, 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 nuclear and coal-fired 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 will serve vary from year to year.

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Pricing for the BGS contracts for recent and future periods by purchasing utility, including a capacity component, is as follows:

Load Zone ($/MWh)	2006-2009	2007-2010	2008-2011	2009-2012	2010-2013
PSE&G	$ 102.51	$ 98.88	$ 111.50	$ 103.72	$ 95.77
Jersey Central Power and Light	$ 100.44	$ 99.64	$ 114.09	$ 103.51	$ 95.17
Atlantic City Electric	$ 103.99	$ 99.59	$ 116.50	$ 105.36	$ 98.56
Rockland Electric Company	$ 111.14	$ 109.99	$ 120.49	$ 112.70	$ 103.32

A portion of our total capacity is hedged through the BGS auctions. On average, tranches won in the BGS auctions require 100 MW to 120 MW of capacity on a daily basis.

We have obtained price certainty for all of our PJM and New England capacity through May 2013 through the RPM and FCM pricing mechanisms.

We enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation. There is, however, 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 versus 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 delivery company, that is, the load that remains after some customers have chosen to be served directly by third party suppliers. The amount of power supplied varies based on the level of the delivery company 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 2009, as market prices declined from past years historic highs, there has been an incentive for more of the smaller commercial and industrial electric customers to switch. In a falling price environment, this has a negative impact on Power s margins, as the anticipated BGS pricing is replaced by lower market pricing. We are unable to determine the degree to which this switching, or migration , will continue, but the impact on our results could be material.

To support our contracted sales of energy, we entered into contracts for the future purchase and delivery of nuclear fuel and coal, which include some market-based pricing components. As of February 15, 2010, we had contracted for the following percentages of our nuclear and coal generation output and related fuel supplies for the next three years with modest amounts beyond 2012.

Nuclear and Coal Generation	2010	2011	2012
Generation Sales	90%-95%	50%-60%	15%-30%
Nuclear Fuel Purchases	100%	100%	100%
Coal Supply and Transportation Costs	95%-100%	30%-40%	5%-10%

We take a more opportunistic approach in hedging our anticipated natural gas-fired generation. The generation from these units is less predictable, as these units are generally dispatched when aggregate market demand has exceeded the supply provided by lower-cost units. The natural gas-fired units have generally provided a lower contribution to our margin than either the nuclear or coal units, although recent market price dynamics of coal and gas moderated this historical relationship for 2009.

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 5.5 million people, or about 70% of the State s population, reside.

Products and Services

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

- **Transmission** is 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** is 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 non-tariff competitive services, such as appliance repair services. The commodity supply portion of our utility business electric and gas sales are 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 improve efficiencies in customer energy use and increase the level of renewable generation including:

- a program to help finance the installation of 81 MW of solar power systems throughout our electric service area,

- a program to develop, own and operate 80 MW of solar power systems over four years, and

- a set of energy efficiency programs to encourage conservation and energy efficiency by providing energy and money 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 2.1 million electric customers and 1.7 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately 300 suburban and rural communities.

Transmission

We use formula rates for our existing and future 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. Currently, approved rates provide for a ROE of 11.68% on existing and new transmission investment. FERC has also approved incentive rate treatment for two new transmission lines, which when added to the approved base ROE, will yield a ROE of 12.93% for these projects. We will also earn this ROE on Construction Work In Progress (CWIP) dollars spent on these projects.

Transmission Statistics

December 31, 2009		Historical Annual
Network Circuit Miles	**Billing Peak (MW)**	**Growth 2005-2009**
1,442	9,687	0.50%

For more information on current transmission construction activities, see Regulatory Issues, Federal Regulation Transmission Regulation.

Distribution

Our primary business is the distribution of gas and electricity to end users in our service territory. Our load requirements were split during 2009 among residential, commercial and industrial customers, described below. We believe that we have all the non-exclusive franchise rights (including consents) necessary for our electric and gas distribution operations in the territory we serve.

	% of 2009 Sales	
Customer Type	**Electric**	**Gas**
Commercial	58%	36%
Residential	31%	60%
Industrial	11%	4%
Total	**100%**	**100%**

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

Electric and Gas Distribution Statistics

	December 31, 2009		Historical Annual
	Number of Customers	**Electric Sales and Gas Sold and Transported**	**Load Growth 2005-2009**
Electric	2.1 Million	41,961 GWh	-0.6%
Gas	1.7 Million	3,500 Million Therms	-0.4%

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Supply

Although commodity revenues make up more than 60% of our revenues, we make no profit 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. However, pursuant to BPU requirements, we serve as the supplier of last resort for electric and gas customers within our service territory who have not chosen 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 two concurrent auctions authorized by the BPU for New Jersey s total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey s electric distribution companies (EDCs). Once validated by the BPU, electricity prices for BGS service are set.

We procure the supply requirements of our default service gas customers (BGSS) 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

There continues to be 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 both electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs 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 see Item 7. MD&A.

Energy Holdings

With the transfer of the two Texas generation facilities to Power in October 2009 and the sale of almost all of our investments in international generation and distribution over the past few years, our focus at Energy Holdings is on managing our portfolio of leveraged lease investments and domestic generation investments. Through Energy Holdings, we are also pursuing solar and other renewable generation projects, as discussed below. For additional information on Energy Holdings generation facilities, see Item 2. Properties.

Products and Services

The majority of our $1.6 billion in leveraged lease investments are energy-related. As of December 31, 2009, the single largest lease investment represented 20% of total leveraged leases.

Our 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 in 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 GAAP, the 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 related to certain lessees, see Item 1A. Risk Factors, Item 7. MD&A Results of Operations Energy Holdings, Item 7A. Quantitative and Qualitative Disclosures About Market Risk Credit Risk Energy Holdings and Note 12. Commitments and Contingent Liabilities.

Our domestic generation projects in California, Hawaii and New Hampshire, totaling 358 MW, are contracted under long-term Power Purchase Agreements (PPAs).

Energy Holdings has developed a 2 MW solar project in western New Jersey, currently in service, and acquired two additional solar projects of 27 MW, currently under construction in Florida and Ohio. Completion of the Florida and Ohio projects is expected by the end of 2010. The total investment for the three projects will be approximately $114 million.

In August 2008, we invested in a joint venture to license compressed air energy storage (CAES) technology. CAES technology stores energy in the form of compressed air which can later be released to generate electricity through specialized turbine equipment. This technology could be used to optimize an intermittent energy source, such as wind, by storing energy at night and releasing this stored energy during the day when customers need power. This technology can also be utilized to augment the capacity of Combined Cycle Gas Turbines, returning the units closer to their nameplate capacity when they are encountering reductions due to ambient conditions.

In October 2008, the New Jersey Office of Clean Energy (OCE) awarded a $4 million grant to a joint venture owned equally by us and an unaffiliated private developer, to advance the development of a 350 MW wind site to be located approximately 16 miles off the shore of southern New Jersey. An offshore wind site has not yet been developed and constructed in the U.S. Numerous issues, including federal and state permitting, environmental impacts, power output sale arrangements, construction approach and expected maintenance costs, will need to be resolved in order to successfully develop such a project.

COMPETITIVE ENVIRONMENT

Power

Various market participants compete with us and one another in buying and selling in wholesale power pools, 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

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load requirements. A reduction in load requirements can also be caused by economic cycles and 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 transmission planning or cost allocation could also impact our revenues.

We are also at risk if one or more states in which we operate should decide to turn away from competition and allow regulated utilities to own or reacquire and operate generating stations in a regulated and potentially uneconomic manner, or to encourage rate-based construction of new generating units. This has occurred in certain states. The lack of consistent rules in energy markets can negatively impact the competitiveness of our plants. Also, regional inconsistencies in environmental regulations, particularly those related to emissions, have put some of our plants which are located in the Northeast, where rules are more stringent, at an economic disadvantage compared to our competitors in certain Midwest states.

Environmental issues, such as restrictions on carbon dioxide (CO_2) emissions 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. While our generation fleet is relatively low-emitting, additional restrictions could have a negative impact on certain of our units, including our coal units.

In addition, pressures from renewable resources, such as wind and solar, could increase over time, especially if government incentive programs continue to grow. For example, over the past several years, a sizable amount of wind generation capacity has been constructed in ERCOT, particularly in western Texas, which has impacted our Odessa generation facility located in that area. Given the favorable wind conditions in western Texas, these wind generation facilities are able to produce power during a substantial period of the year, resulting in an additional source of generation, especially during off-peak seasons. Numerous competitors have announced plans to build substantial amounts of new wind generation capacity in the western part of Texas, where power demand is relatively low, but there are transmission constraints in the ability to get power to the load centers. The Public Utility Commission of Texas is attempting to address the constraint issue, but it is not clear if these efforts at transmission expansion will be successful or, if so, what the economic impact will be. As a result of such potential transmission expansion, it is possible that additional amounts of wind generation may be built in ERCOT, potentially impacting market prices and our competitiveness.

PSE&G

The transmission and distribution business has minimal risks from competitors. 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.

EMPLOYEE RELATIONS

As of December 31, 2009, we had approximately 10,352 employees in the following companies, including 6,627 covered under collective bargaining agreements.

Employees as of December 31, 2009

	Power	PSE&G	Energy Holdings	Services
Non-Union	1,345	1,325	20	1,035
Union	1,561	5,057		9
Total Employees	**2,906**	**6,382**	**20**	**1,044**
Number of Union Groups	3	5	n/a	1

All of our collective bargaining agreements, except one will expire on April 30, 2013 or later. The one exception is an agreement at PSE&G that covers 1,218 employees. This agreement expires on April 30, 2011.

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REGULATORY ISSUES

Federal Regulation

FERC

FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G, Power s generation and energy trading subsidiaries and one subsidiary of Energy Holdings are public utilities as defined by the FPA. FERC has extensive oversight over public utilities as defined by the FPA. FERC approval is usually required when a public utility company seeks to: sell or acquire an asset that is regulated by FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

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

FERC also regulates ISOs, such as PJM, and their energy and capacity markets.

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

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

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 FERC for authority to make market based rate (MBR) sales. For a requesting company to receive MBR authority, FERC must first make a determination that the requesting company lacks market power in the relevant markets. FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power.

PSE&G and certain subsidiaries of Power and Energy Holdings have received MBR authority from FERC. Retention of MBR authority is critical to the maintenance of our generation business revenues.

Under MBR rules, FERC may look at sub-markets to analyze whether a company possesses market power. Applying these rules in October 2008, FERC granted PSE&G, PSEG Energy Resources & Trade LLC and PSEG Power Connecticut LLC continued MBR authority and granted both PSEG Fossil LLC and PSEG Nuclear LLC initial MBR authority. Each of these companies will be required to file for continuation of its MBR authority by the end of 2010.

Cost-Based RMR Agreements FERC has permitted public utility generation owners to enter into RMR agreements that provide cost-based compensation to a generation owner when a unit proposed for retirement is asked to continue operating for reliability purposes. Our Hudson 1 generating station is currently operating under an RMR agreement which expires September 2011.

In ISO-NE, many owners of generation facilities have also filed for RMR treatment. We currently collect FERC-approved monthly payments for the Bridgeport Harbor Station Unit 2 and the New Haven Harbor Station. These agreements are scheduled to expire in June 2010.

RMR treatment has enabled these units to continue to operate. Various parties have challenged the continuation of RMR payments in ISO-NE and, thus, there is risk that such payments may be terminated prior to the end of the current contract terms.

Reactive Power Reactive power encompasses certain ancillary services necessary to maintain voltage support and operate the system. In 2008, we filed a reactive power Tariff with FERC, which was subsequently approved. Under this Tariff, we receive $28.5 million annually as compensation for the provision of reactive power.

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 rules, bids are subject to price caps and mitigation rules applicable to certain generation units. FERC rules also govern the overall design of these markets. At present, all units 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 Markets

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

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. PJM s RPM and related FERC orders establishing prices paid to us and other generators as a result of RPM s transitional auctions are being challenged in court by various state public utility commissions, including the BPU. These legal actions remain pending. Moreover, the mechanics of RPM in PJM continue to evolve and be refined in stakeholder proceedings in which we are active.

Pursuant to a settlement that established the design of ISO-NE s market for installed capacity and which is being implemented gradually over a four-year period that commenced in December 2006, all generators in New England began receiving fixed capacity payments that escalate gradually over the transition period. 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 the ISO-NE continue to develop. ISO-NE is expected to be filing soon with FERC to establish market rules for the fourth FCM auction to be held in August 2010.

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. Discussions concerning potential changes to NYISO capacity markets are also ongoing.

Capacity market rules in all of these markets may change in the future.

Transmission Regulation

FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are 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 large scale transmission investments. In October 2009, PSE&G filed its 2010 transmission rates with FERC and the rates became effective January 1, 2010. On February 2, 2010 FERC issued an order accepting our filing. The update provides for approximately $23 million in increased revenues as part of our 2010 transmission rates.

Transmission Expansion In June 2007, PJM identified the need for the construction of the Susquehanna-Roseland line, a new 500 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 for the New Jersey and Pennsylvania portions of the project, respectively. The estimated cost of our portion of this construction project is approximately $750 million, and PJM has directed that the line be placed into service by June 2012. On February 11, 2010, PSE&G received approval from the BPU to construct the New Jersey portion of the project. Additional approvals remain pending. For further discussion, see State Regulation Energy Policy Susquehanna-Roseland BPU Petition.

Construction of the Susquehanna-Roseland line is contingent upon obtaining all necessary federal, state, municipal and landowner permits and approvals. The construction of the line has encountered local opposition. Should the line be cancelled for reasons beyond our control, we will be entitled to recover 100% of prudently-incurred abandonment costs.

In December 2008, PJM approved another 500 kV transmission project, originating in Branchburg and ending in Hudson County, New Jersey. This project is still in the design phase and will require the receipt of numerous regulatory approvals prior to construction. In October 2009, we filed a petition with FERC seeking incentive rates for the planned project. In December 2009, FERC granted our request for incentive rate treatment. We will receive a ROE adder of 125 basis points above its base ROE, recovery of one hundred percent of Construction Work in Progress in rate base and authorization to recover 100% of all prudently-incurred development and construction costs if the project is abandoned or cancelled, in whole or in part, for reasons beyond our control. The estimated cost of the project is approximately $1.1 billion. PJM has specified a June 2013 in-service date for this project.

U.S. Department of Energy (DOE) Congestion Study, National Interest Electric Transmission Corridors and FERC Back-Stop Siting Authority By virtue of the Energy Policy Act, the DOE has the ability to designate transmission corridors in areas found to be critical congestion areas, which then gives FERC the ability to site transmission projects within these corridors should certain events occur.

In October 2007, the DOE acted to designate transmission corridors within these critical congestion areas. One of the designated corridors is the Mid-Atlantic Area National Corridor which includes New Jersey, most of Pennsylvania and New York. Thus, entities seeking to build transmission within the Mid-Atlantic Area Corridor may be able to use FERC s back-stop siting authority under certain circumstances, if necessary, to site transmission, including the Susquehanna-Roseland line. In February 2009, the United States Court of Appeals for the Fourth Circuit issued a decision that would narrow the scope of FERC s back-stop siting authority. The United States Supreme Court has declined to review this decision. The DOE is required by statute to issue a new congestion study in 2010.

PJM Transmission Rate Design In 2007, FERC addressed the issue of how transmission rates, paid by PJM transmission customers and ultimately paid by our retail customers, should be designed in PJM. FERC ruled that the cost of new high voltage (500 kV and above) transmission facilities in PJM would be regionalized and paid for by all transmission customers on a pro-rata basis, which share is calculated annually based upon a zone s load ratio share within PJM. For all existing facilities, costs would be allocated using the pre-existing zonal rate design. For new lower voltage transmission facilities, costs would be allocated using a beneficiary pays approach. This FERC decision was subsequently upheld on rehearing but was then appealed by other parties to the United States Court of Appeals for the Seventh Circuit.

In August 2009, the Court ruled that with respect to new 500 kV and higher centrally-planned facilities, FERC had not adequately justified its decision to regionalize these costs. Certain parties sought rehearing of the Court s decision, which requests have been denied. The case has now been remanded to FERC for further proceedings. FERC has established procedures for review of this issue. The current allocation for new 500 kV and higher centrally-planned projects may remain in place or could be modified by FERC.

Compliance

Reliability Standards Congress has required FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability

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of the U.S. 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. Since these standards are mandatory and applicable to, among other entities, transmission owners and generation owners and operators, we are obligated to comply with the standards and to ensure continuing compliance. Our Texas and California generation assets, as well as PSE&G, have already undergone formal audits, and our generation assets in PJM will be audited in 2011. In addition, many of our operating companies have been subject to spot audits. NERC compliance represents a significant area of compliance responsibility for us. As a result of a PSE&G audit, NERC has assessed a penalty of five thousand dollars with respect to a potential violation of one NERC standard. This penalty is now pending at FERC.

FERC Standards of Conduct In October 2008, FERC issued a revised rule governing the interaction between transmission provider (i.e. PSE&G) employees and wholesale merchant employees (housed largely in Power), which revises FERC s Standards of Conduct by abandoning the corporate separation approach to regulating these interactions and instead adopting an employee function approach, which focuses on an individual employee s job functions in determining how the rules will apply. The effect of these rules will be to permit more affiliate communication with respect to corporate and strategic planning, to loosen restrictions on senior officers and directors and to permit necessary operational communications between those employees engaged in transmission system operations and planning and those employees engaged in generating plant operations. In October 2009, FERC revised these rules to further define which employees are covered by the rules. Because of the rules focus on employee functions, all of our FERC regulated companies will need to continue to monitor developments in this area.

Market Behavior/Anti-Manipulation Rules FERC has rules in place to govern the behavior of participants in the wholesale energy markets that it regulates. These rules prohibit such participants from engaging in certain types of transactions, such as withholding generating capacity to artificially increase prices, engaging in wash trades and providing erroneous or misleading information to, or withholding material information from, Regional Transmission Organizations (RTO)/ISOs. FERC s anti-manipulation rules are broadly written and are intended to prevent market participants from engaging in fraudulent conduct in FERC regulated markets. These rules are now very much a focus of FERC s compliance efforts, and during the last year, FERC has imposed significant monetary penalties on market participants found to be in violation of the rules. All of our companies that do business in FERC regulated markets, such as PSE&G and subsidiaries of Power, must comply with these rules.

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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. In August 2009, we submitted applications to extend the operating licenses of our Salem and Hope Creek facilities by 20 years. No parties have requested a hearing or intervention and the initial filing deadline for such a request as part of the NRC license renewal process has passed. The NRC is expected to spend up to 30 months to review our applications before making a decision. The current operating licenses of our nuclear facilities expire in the years shown below:

Unit	Year
Salem Unit 1	2016
Salem Unit 2	2020
Hope Creek	2026
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

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. 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 some state regulation in California, Connecticut, Hawaii, New Hampshire, New York, Pennsylvania and Texas due to our ownership of generation and/or transmission facilities 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. The BPU also has authority to adjust rates downward if it finds that the rates it approved are no longer just and reasonable. In May 2009, we petitioned the BPU for an increase in electric and gas base rates. We filed an update in January 2010 requesting an increase of $148 million and $74 million for electric and gas, respectively. The matter is pending with a decision expected in the first half of 2010. No assurances can be given regarding the outcome of this proceeding.

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Rate Adjustment Clauses In addition to base rates, we recover certain costs from customers pursuant to mechanisms, known as adjustment clauses. These clauses permit, at set intervals, the flow-through of costs to customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs are subject to BPU approval. Costs associated with these clauses are deferred when incurred and amortized to expense when recovered in revenues. Delays in the pass-through of costs under these clauses can result in significant changes in cash flow. Our Societal Benefits Charges (SBC) and Non-utility Generation Charges (NGC) clauses are detailed in the following table:

Rate Clause	**2009 Revenue**	**(Over) Under Recovered Balance as of December 31, 2009**
	Millions	
Energy Efficiency and Renewable Energy	$ 197	$ (4)
Remediation Adjustment Charges (RAC)	18	137
USF	179	8
Social Programs	54	47
Total SBC	**448**	**188**
NGC	102	86
Total	**$ 550**	**$ 274**

SBC The SBC is a mechanism designed to ensure recovery of costs associated with activities required to be accomplished to achieve specific government-mandated public policy determinations. The programs that are covered by the SBC (gas and electric) are energy efficiency and renewable energy programs, Manufactured Gas Plant Remediation Adjustment Charge (RAC) and the Universal Service Fund (USF). In addition, the electric SBC includes a Social Programs component. All components include interest on both over and under recoveries.

NGC The NGC recovers the above market costs associated with the long-term power purchase contracts with non-utility generators approved by the BPU.

Recent Rate Adjustments

USF/Lifeline The USF is an energy assistance program mandated by the BPU under state law to provide payment assistance to low-income customers. The Lifeline program is a separately mandated energy assistance program to provide payment assistance to elderly and disabled customers. In October 2009, revised rates were put in place. Our USF rates will recover $75 million and $38 million for electric and gas, respectively. Our Lifeline rates will recover $29 million and $16 million for electric and gas, respectively. We earn no margin on the collection of the USF or Lifeline programs, resulting in no impact on Net Income.

SBC/NGC In February 2009, we filed a petition requesting a decrease in our electric SBC/NGC rates of $18.9 million and an increase in gas SBC rates of $3.7 million. In July 2009, a revision was filed requesting an increase in SBC/NGC rates of $104 million and $15 million for electric and gas, respectively. The electric increase was due to increased non-utility generation (NUG) contract costs. We expect an initial decision from the Administrative Law Judge in March and a BPU order in April 2010. No assurances can be provided as to the outcome of these proceedings.

RAC In November 2009, we filed a RAC 17 petition with the BPU requesting an increase in electric and gas RAC rates of approximately $13.4 million and $10.5 million, respectively. This matter was transferred to the Office of Administrative Law.

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. PSE&G earns no margin on the provision of BGS.

PSE&G s total BGS-Fixed Price eligible load is expected to be approximately 8,500 MW. Approximately one-third of this load is auctioned each year for a three-year term. Current pricing is as follows:

	2007	2008	2009	2010
36 Month Term Ending	May 2010	May 2011	May 2012	May 2013
Load (MW)	2,758	2,800	2,900	2,800
$ per kWh	$ 0.09888	$ 0.11150	$ 0.10372	$ 0.09577

(a) Prices set in the February 2010 BGS Auction are effective on June 1, 2010 when the 36-month (May 2010) supply agreements expire.

In December 2009, the BPU decided that, after the 2010 BGS auction, it would hold a technical conference to consider enhancements to the BGS auction. Any action taken in response to that hearing is likely to be implemented for the BGS auctions in 2011 or future years. The BPU may address many issues, including the impact of potential development of incremental generation in New Jersey. No assurances can be provided as to the outcome of these proceedings.

For additional information, see Item 8. Financial Statements and Supplementary Data Note 6. Regulatory Assets and Liabilities and Note 12. 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 has a full requirements contract through March 2012 with Power to meet the supply requirements of default service gas customers. 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 May 2009, PSE&G made its annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $133 million, excluding Sales and Use Tax, to be effective October 1, 2009. This represents a reduction of approximately 7% for a typical residential gas heating customer. The BPU approved the new lower BGSS rate on September 16, 2009 and it became effective immediately.

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 October 2008. The plan identifies a number of the actions to improve energy efficiency, increase the use of renewable resources, ensure a reliable supply of energy and stimulate investment in clean energy

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technologies. Given the gubernatorial change in New Jersey, it is unclear what changes to the EMP and its policy goals may result. We have approval from the BPU to implement several programs addressing different components of the EMP goals to improve efficiencies in customer use and increase the level of renewable generation in New Jersey.

Solar Initiatives In order to spur investment in solar power in New Jersey and meet energy goals under the EMP we have undertaken two major initiatives at PSE&G. The first program helps finance the installation of 81 MW of solar systems throughout our electric service area by providing loans to customers. The first part of this initiative was a pilot program approved by the BPU in April 2008. The program was expanded beyond its pilot phase in December 2009. The program is similar to the original pilot program, but it is available only for systems up to 500kW. 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 will be used to offset program costs.

The total investment of both phases of the Solar Loan Program will be approximately $248 million once the program is fully subscribed, projects are built and loans are closed. As of December 31, 2009, we have provided $43 million in loans for 53 projects representing 11.6 MW.

The second solar initiative is the Solar 4 All Program that was approved by the BPU in July 2009. Under this program, we are investing approximately $515 million to develop 80 MW of utility-owned solar photovoltaic (PV) systems over four years. The program consists of systems 500kW or greater installed on PSE&G-owned property (25 MW), solar panels installed on distribution system poles (40 MW) and PV systems installed on third-party sites in our electric service territory (15 MW). We will sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition we will sell the SRECs received from the projects through the same auction used in the loan program. Proceeds from these sales will be used to offset program costs.

As of December 31, 2009, 1 MW of solar panels had been installed on distribution poles. On January 6, 2010, we announced that we had entered into contracts with four developers for 12 MW of solar capacity to be developed on land we own in Edison, Linden, Trenton and Hamilton. The projects represent an investment of approximately $50 million. Construction is expected to start this spring pending receipt of all approvals.

Demand Response (DR) In 2008 the BPU directed that DR programs be implemented by each of New Jersey s electric utilities and established targets to increase DR by a total of 600 MW by the end of the third year, with our responsibility being 55% of the total (330 MW). We filed our program proposal and identified $93.4 million of demand response investment over a period of four years, seeking full recovery of the program costs, including a return on our investment, through rates.

In July 2009, the BPU approved a portion of our program that focuses on air conditioning load control in the residential and small commercial customer segments. The investment represents $65.3 million with a target of 150 MW to be achieved. The remaining portion of our filing is awaiting further action by the BPU, but no timetable has been established to complete the proceeding. As of December 31, 2009, we had installed approximately 1.2 MW.

Also in 2008, the BPU directed each of the State s electric utilities to administer a one-year program designed to develop an additional 600 MW of DR resources. The utilities role was to collect funding through rates and make payments to Curtailable Service Providers who signed up the new or incremental DR resources. The incentive was set by the BPU at $22.50/MW-day with a statewide budget of $4.9 million. Our share was set at 59.54%, or 195 MW, with a budget of $3.4 million. Funding for the program, called the Demand Response Working Group Modified Program, was

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collected through a component of the Regional Greenhouse Gas Initiative (RGGI) Adjustment Clause in 2009. We anticipate paying approximately $1.1 million in February 2010 for the 132 MW verified by PJM.

Energy Efficiency Initiatives We have been approved by the BPU to implement two energy efficiency initiatives, both of which were filed under New Jersey s RGGI legislation, which encourages utilities to invest in conservation and energy efficiency programs as part of their regulated business. Both initiatives are intended to help New Jersey meet its EMP goal of reducing energy consumption by 20% by 2020 and to help improve New Jersey s economy through the creation of new jobs through the promotion of energy efficiency.

- ***Carbon Abatement Program*** The BPU approved our proposal to invest up to $46 million over four years on a small scale carbon abatement program across specific customer segments. New rates were effective on January 1, 2009. For each year of the program we will file a petition on October 1st to set forth the calculation of the electric and gas recovery charges for the subsequent year. The BPU approved a rate increase in December 2009, which will result in a net annual revenue increase of $1.9 million in 2010.

- ***Energy Efficiency Economic Stimulus Program*** In July 2009, the BPU approved our energy efficiency program developed to stimulate economic growth in the state. Under this program, we anticipate approximately $190 million in energy efficiency expenditures over an 18 month period. The program provides for a charge for recovery of program expenditures plus an allowed return.

The energy efficiency initiatives target multiple customer segments. Subprograms provide energy audits and incentives for energy retrofit services to homes and small businesses in Urban Enterprise Zone municipalities, multi-family buildings, hospitals, data centers and governmental entities. Other initiative components include funding for new technologies and demonstration projects, and a program to encourage non-residential customers to reduce energy use through improvements in the operation and maintenance of their facilities.

Capital Economic Stimulus Infrastructure Program In January 2009, we filed for approval of a capital economic stimulus infrastructure investment program. Under this initiative, we proposed to undertake $698 million of capital infrastructure investments over a 24 month period. The goal of these accelerated capital investments is to help improve the State s economy through the creation of new jobs. This filing was made in response to the Governor of New Jersey s proposal to help revive the economy through job growth and capital spending.

In April 2009, the BPU approved a settlement agreement which identified 38 qualifying projects totaling $694 million. These projects are expected to create more than 900 new jobs. We received the BPU s written order effective May 1, 2009, which provides increases of $7 million for electric and $12 million for gas rates annually. Under the program, new Capital Adjustment Charges (CAC) will provide for immediate recovery of a return on program expenditures plus depreciation of the assets. The CAC will be adjusted each January based on forecasted program expenditures and will be subject to deferred accounting. The rates are subject to annual adjustments based on actual expenditures and market conditions.

In November 2009, PSE&G made a filing in the above-referenced matter, requesting approximately $35 million for electric and $17 million for gas in revenue, on an annual basis for a combined total of $52 million. Compared to the existing BPU approved CAC rates, the resultant total net annual revenue impact on the electric and gas customers is a $33 million increase over the 2009 rates. In December 2009, the BPU approved a stipulation to reset the CAC effective January 1, 2010.

Susquehanna-Roseland BPU Petition In January 2009, we filed a Petition with the BPU seeking authorization to construct the New Jersey portion of the Susquehanna-Roseland line. The New Jersey portion of the line spans approximately 45 miles and crosses through 16 municipalities. The Petition seeks a finding from the BPU that municipal land use and zoning ordinances do not apply to this line.

On February 11, 2010, the BPU granted approval to PSE&G to construct the New Jersey portion of this project. In June 2009, the New Jersey Highlands Council provided a favorable applicability determination with respect to the portion of the project crossing the Highlands region, and the New Jersey Department of Environmental Protection (NJDEP) approved this determination on January 15, 2010. We are in the process of seeking to obtain all other necessary environmental permits for the project, including from the National Park Service, as may be necessary. Failure to obtain all permits on a timely basis could delay the project.

BPU Audits

The BPU has statutory authority to conduct periodic audits of our utility s operations and our compliance with applicable affiliate rules and competition standards. The BPU has begun conducting its periodic combined management/competitive service audits of PSE&G.

Management/Affiliate Audit The BPU engaged a contractor to perform a comprehensive audit with respect to the effectiveness of management and transactions among affiliates, which began in October 2009. According to the BPU schedule the audit will be completed as early as July 2010. A report will be produced which can be expected to include recommendations for changes in practices at PSE&G and affiliates. We will have an opportunity to provide comments. The BPU may enforce the findings in whole or in part by Order.

Deferral Audit The BPU Energy and Audit Division conducts audits of deferred balances. A draft Deferral Audit Phase II report relating to the 12-month period ended July 31, 2003 was released by the consultant to the BPU in April 2005. For additional information regarding the Deferral Audit, see Item 1A. Risk Factors and Note 12. Commitments and Contingent Liabilities.

RAC Audit In February 2008, the BPU s Division of Audits commenced a review of the RAC program for the RAC 12, 13 and 14 periods encompassing August 1, 2003 through July 31, 2006. Total RAC costs associated with this period were $83 million. The BPU has not issued a final order or report. We cannot predict the final outcome of this audit.

ENVIRONMENTAL MATTERS

Environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to address the environmental impacts of historical operations that may have been in full compliance with the requirements in effect at the time those operations were conducted. 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 current 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 and are not included in capital expenditures, but may be material.

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

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

climate change.

For additional information related to environmental matters, including 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 Note 12. Commitments and Contingent Liabilities.

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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.

Title V of 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 capital expenditures, but may be material.

Sulfur dioxide (SO_2), Nitrogen Oxide (NO_x) and Particulate Matter Emissions Since January 1, 2000, the CAA set a cap on SO_2 emissions from affected generating units and allocated SO_2 allowances to those units with the stated intent of reducing the impact of acid rain. Generation units with emissions greater than their allocations can obtain allowances from sources that have excess allowances. We do not expect to incur material expenditures to continue complying with this SO2 program, known as the acid rain program.

The U.S. Environmental Protection Agency (EPA) further regulated SO_2 and NOx by enacting the final Clean Air Interstate Rule (CAIR). In this rule, the EPA identified 28 states and the District of Columbia as contributing significantly to the levels of fine particulates and/or eight-hour ozone air quality in states downwind of those states identified by EPA. New Jersey, New York, Pennsylvania, Texas and Connecticut were among the states the EPA listed as contributing to downwind particulate and eight-hour ozone air quality. Based on state obligations to address interstate transport of air pollutants under the CAA, the EPA had proposed a two-phased emission reduction of both NO_x and SO_2, which are precursors to both particulate matter emissions and ozone air quality. Under CAIR, both NO_x and SO_2 are regulated under two phases, which correspond to the emissions levels expected to be obtained by certain dates during those phases. Phase 1of CAIR was scheduled to begin in 2009 for emissions of NO_x and 2010 for emissions of SO_2. Phase 2 of CAIR for NOx and SO_2 emissions were scheduled to begin in 2015. The EPA is recommending that the program be implemented through a cap-and-trade program, although states are not required to proceed in this manner.

CAIR was challenged by a variety of states, environmental groups and industry groups. In December 2008, the U.S. Court of Appeals for the District of Columbia Circuit remanded CAIR back to the EPA to fix what the Court identified as the flaws within CAIR. The existing CAIR will remain in effect until the EPA issues new rules.

Based upon the remand order, the NO_x trading program commenced in 2009. It is anticipated that, in aggregate, we will be net buyers of annual NO_x allowances but will likely be allocated sufficient allowances to satisfy Ozone season NO_x emissions. At recent market prices of annual NO_x allowances, the cost of our estimated shortfall requirement of 3,000 allowances would be approximately $10 million. The future direction of the market is unclear due to the recent court rulings. The final cost of compliance is uncertain due to market instability.

The SO_2 part of CAIR was initiated on January 1, 2010, and the financial impact to us is anticipated to be minimal due to the surplus allowances banked from the acid rain program that can be used to satisfy CAIR obligations. CAIR redesign is expected to be proposed in the second quarter of 2010. The impacts of this redesign cannot be determined at this time.

Water Pollution Control

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

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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 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, in other words, 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.

For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

Hazardous Substance Liability

The production and delivery of electricity, 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.

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.

Fuel and Waste Disposal

Nuclear Fuel Disposal The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In September 2009, we signed an agreement with the DOE applicable to Salem and Hope Creek under which we will be reimbursed for past and future reasonable and allowable costs resulting from the DOE delay in accepting spent nuclear fuel for permanent disposition. Under this settlement, in October 2009 we received approximately $47 million for our spent fuel management costs incurred through December 2007 and in January 2010 we received approximately $7 million for those costs incurred during 2008. A similar settlement agreement was reached related to Peach Bottom in 2004.

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 for at least 30 years beyond the licensed life for the reactor. We have an on-site storage facility that is expected to satisfy the storage needs of Salem 1, Salem 2 and Hope Creek through the end of their current licenses as well as storage needs over the units anticipated 20 year license extensions. Exelon Generation has advised us that it has an on-site storage facility that will satisfy Peach Bottom s storage requirements until at least 2014.

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Low Level Radioactive Waste As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. 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.

Climate Change

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, have established RGGI intended 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.

States rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO2 emissions. Generators are required to submit an allowance for each ton emitted over a three year period (e.g. 2009, 2010, 2011). Allowances are available through the auction or through secondary markets and are required to be submitted to states by March 2012 for the first period.

Pricing for the allowances will vary based on future allowance market conditions, electric generation market conditions and the possibility of a national greenhouse gas program that may or may not supplant RGGI.

New Jersey also adopted the Global Warming Response Act in 2007, which calls for stabilizing its greenhouse gas 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.

Concurrently, the federal government is considering several bills to define a national energy policy and address climate change. Bills under consideration include provisions to establish a national renewable energy portfolio standard, to establish an energy efficiency resource standard and to implement a cap-and-trade program to reduce greenhouse gas emissions. Provisions contained within these bills may present material risks and opportunities to our businesses. Ultimately, the final design of the federal climate change bill specifically with regard to the stringency and integrity of the carbon cap, the design of price control mechanisms, rules governing the use of offsets, how emissions allowances are allocated and provisions for preemption of State, regional, and EPA programs will determine the impact of the legislation on us. We will not be able to reasonably estimate these impacts until final legislation is passed.

The EPA has issued an endangerment finding for greenhouse gas emissions, and is in the process of defining how it will apply Preventions of Significant Deterioration (PSD)/ Best Available Control Technology (BACT) requirements for greenhouse gas emissions at new and or modified sources. The scope and stringency of these requirements will determine their impact to the electric power industry and us.

For additional information on various activities at the federal level during 2009 related to addressing global climate change, see Item 7. MD&A Overview of 2009 and Future Outlook.

The outcome of global climate change initiatives cannot be determined; however, adoption of stringent CO_2 emissions reduction requirements in the Northeast, including the potential allocation of allowances to our facilities and the prices of allowances available through auction, could materially impact our operations. The financial impact of a requirement to purchase allowances for emissions of CO_2 would be greatest on coal-fired generating units because they typically have the highest CO_2 emission rate and therefore, need to purchase the most allowances. Gas-fired units would require fewer allowances and nuclear units would not need any allowances.

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Any addition of CO_2 limit requirements under a national program could impose an additional financial impact on our fossil generation activities beyond that imposed by existing state and regional programs. It is premature to determine the positive or negative financial impact of a future federal climate change program because it is difficult to determine the effect of such program on the dispatch of our electric generation units compared to the dispatch of other power generating companies, particularly those which may have a larger carbon footprint.

While there would be increased costs relating to these evolving regulations, the efforts to reduce greenhouse gases could lead to increased opportunities associated with renewable generation and other alternative fuels. Moreover, to the extent that a carbon charge applies to gas and coal generation, we could experience higher margin from the sale of energy produced by our nuclear facilities. However, it is premature to attempt to quantify the possible costs and other implications of our generation facilities.

In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings not involving our companies could be material in the future liability of energy companies on alleged impacts of global climate change. Litigation has been commenced by individuals, local governments and interest groups alleging that various industries, including various energy companies, emitted greenhouse gases causing global climate change that resulted in a variety of damages. If relevant Federal or state common law were to develop that imposed liability upon those that emit greenhouse gases for alleged impacts of greenhouse gas emissions, such potential liability could be material.

SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Note 21. 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 affect 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 business.

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 business, such as our ability to:

- ***Obtain fair and timely rate relief*** Our utility s base rates for electric and gas distribution are subject to regulation by the BPU and are effective until a new base rate case is filed and concluded. In addition, limited categories of costs such as fuel are recovered through adjustment clauses that are periodically reset to reflect current costs. Our transmission assets are regulated by FERC and costs are recovered through rates set by FERC. Inability to obtain a fair return on our investments or to timely recover material costs not included in rates would have a material adverse effect on our business.

- ***Obtain required regulatory approvals*** The majority of our businesses operate under MBR authority granted by FERC, which has determined that our subsidiaries do not have market power and MBR rules have been satisfied. Failure to maintain MBR eligibility, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on us.

We may also require various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter

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into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals could materially adversely affect our results of operations and cash flows.

Obtain adequate levels of energy and capacity payments The rules governing the energy and capacity markets in which we participate are approved by FERC and are subject to change. These rules have been challenged and will continue to be challenged in the future. Changes may have an adverse impact on the amount of payments we receive in these markets

Comply with regulatory requirements There are Federal standards in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. These standards apply to all transmission owners and generation owners and operators. We have been, and will continue to be, periodically audited by NERC for compliance. In addition, as of December 31, 2009, our companies with critical cyber assets must be in compliance with NERC s Critical Infrastructure Protection (CIP) Standards. FERC can impose penalties up to $1 million per day per violation. In addition, FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, interlocking directorate rules and cross-subsidization.

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. We are currently in the process of undergoing a management audit and an affiliate transactions audit. While we believe that we are in compliance, we cannot predict the outcome of such audits.

There are two pending issues at the BPU stemming from the restructuring of the utility industry in New Jersey several years ago.

Treatment of previously approved stranded costs Our utility securitized $2.525 billion of generation and generation-related costs pursuant to an irrevocable, non-bypassable BPU financing order issued pursuant to the Competition Act. The authority of the BPU to issue its order was upheld by the New Jersey Supreme Court in 2001. The Competition Act created a property right in such financing order that was sold to a bankruptcy remote special purpose subsidiary of PSE&G. An action filed in 2007, seeking injunctive relief from our continued collection of the related transition bond charges, as well as recovery of amounts previously charged and collected, was summarily dismissed by the New Jersey Superior Court and affirmed on appeal in February 2009. The New Jersey Supreme Court denied the plaintiff s petition for certification in May 2009. In addition, a related petition was filed at the BPU, and our Motion to Dismiss the petition remains pending. For additional information, see Legal Proceedings. We cannot predict the outcome of the action pending at the BPU.

Market Transition Charge (MTC) collected during the four-year industry transition period The BPU has raised certain questions with respect to the reconciliation method we employed in calculating the over-recovery of MTC and other charges during the four-year transition period from 1999 to 2003. The amount in dispute was $114 million, which if required to be refunded to customers with interest through December 2009 would be $142 million. In January 2009, an Administrative Law Judge (ALJ) issued a decision which upheld our central contention that the 2004 BPU order approving the Phase I settlement resolved the issues now raised by the BPU Staff and the New Jersey Division of Rate Counsel, and that these issues should not be subject to re-litigation in respect of the first three years of the transition period. The ALJ s decision states that the BPU could elect to convene a separate proceeding to address the fourth and final year reconciliation of MTC recoveries. The amount in dispute with respect to this Phase II period is approximately $50 million.

By order dated September 3, 2009, the BPU rejected the ALJ s initial decision, elected to maintain jurisdiction over the matter and established a schedule for briefing on the merits of the question of whether any MTC-related refunds are due. Generally, the BPU rejected the claims that the matters at issue had been fairly and finally litigated. Briefing has been completed and the matter is now pending before the BPU. We cannot predict the outcome of this proceeding.

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Certain of our leveraged lease transactions may be successfully challenged by the IRS, which would have a material adverse effect on our taxes, operating results and cash flows.

We have received Revenue Agent s Reports from the IRS with respect to its audit of our federal corporate income tax returns for tax years 1997 through 2003, which disallowed all deductions associated with certain leveraged lease transactions. In addition, the IRS Reports proposed a 20% penalty for substantial understatement of tax liability.

As of December 31, 2009, $660 million would become currently payable if we conceded all of the deductions taken through that date. We deposited a total of $320 million to defray potential interest costs associated with this disputed tax liability and may make additional deposits in 2010. As of December 31, 2009, penalties of $150 million could also become payable if the IRS is successful in its claims. If the IRS is successful in a litigated case consistent with the positions it has taken in a generic settlement offer recently proposed to us, an additional $80 million to $100 million of tax would be due for tax positions through December 31, 2009.

We are subject to numerous federal and state environmental laws and regulations that may significantly limit or affect our business, 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 increased 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 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 greenhouse gases produced by our fossil generation facilities*** Federal and state legislation and regulation designed to address global climate change through the reduction of greenhouse gas emissions could materially impact our fossil generation facilities. Legislation enacted in New Jersey 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, primarily in the Northeastern U.S., are developing or have developed state-specific or regional legislative initiatives to stimulate CO_2 emissions reductions in the electric power industry. The RGGI began in 2009. Member states will control emissions of greenhouse gases by issuance of allowances to emit CO_2 primarily through an auction.

A significant portion of our fossil fuel-fired electric generation is located in states within the RGGI region and competes with electricity generators within PJM not located within a RGGI state. The costs or inability to purchase CO_2 allowances for our fleet operating within a RGGI state could place us at an economic disadvantage compared to our competitors not located in a RGGI state.

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.

If the NJDEP and the Connecticut Department of Environmental Protection were to require installation of closed-cycle cooling or its equivalent at our 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.

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 deposited 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.

In 2007, the State of New Jersey 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 12. 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 national ambient air quality standards for one or more air contaminants. 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 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. The EPA has announced that it is reconsidering whether coal ash should be regulated, potentially as a hazardous waste. The EPA has indicated that it intends to propose a rule in early 2010. 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. This potential regulation could also have an impact on certain of our lease investments in coal-fired generation.

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 2016, 2020, 2026, 2033 and 2034. While we have applied for extensions to these licenses for Salem and Hope Creek, the extension process can be expected to take three to five years from commencement until completion of NRC review. We cannot be sure that we will receive the requested extensions or be able to operate the facilities for all or any portion of any extended license.

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. For additional information, see our discussion of operational performance for all of our generation facilities below.

Nuclear Incident or Accident Risk Accidents and other unforeseen problems have occurred at nuclear stations both in the U.S. and elsewhere. The consequences of an accident can be severe and may include loss of life, property damage and/or a change in the regulatory climate. All our nuclear units are located at one of 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. Various rules have recently been implemented to respond to commodity pricing, reliability and other industry concerns. 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 are currently being challenged in court, and FERC is currently considering changes to PJM s rules for RPM and for the Forward Capacity Market in New England. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

Many factors will affect the capacity pricing in PJM, including but not limited to:

- changes in load and demand,
- changes in the available amounts of demand response resources,
- changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.),
- increases in transmission capability between zones, and

changes to the pricing mechanism, including increasing the potential number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time.

Potential changes to the rules governing energy markets in which the output of our plants is sold also poses risk to our business. Certain stakeholders, primarily consumer advocates and state commissions, have been arguing that each generating plant should be paid its as bid price rather than allowing all units to be paid a single clearing price based on the marginal unit s bid. If adopted, this change could reduce the energy payments received by certain of our generating units.

We could also be impacted by a number of other events, including regulatory or legislative actions favoring non-competitive markets and energy efficiency 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. Potential efforts in the State of New Jersey to enact a regulatory construct for the procurement of additional generation could have an impact upon the current competitive market for generation, from which we have benefited. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified by regulations.

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. Developers of long-distance green transmission projects currently have a number of proposed projects pending at FERC. These seek authorization for inclusion in regional transmission planning processes, with the potential to move lower-cost generation to eastern markets, including New Jersey and New York. In addition, the DOE recently awarded funding to the Eastern Interconnection Planning Collaborative (EIPC), which expects to engage in transmission planning across the Eastern Interconnection, making the construction of large-scale transmission more likely. In addition, pressures from renewable resources such as wind and solar, could increase over time, especially if government incentive programs continue to grow.

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,
- 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 an 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, microturbines, windmills and photovoltaic (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 financial results.

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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 will be 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 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. For example, during 2009, generation by our coal units was adversely affected by 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.

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, 2009, it may have had to provide approximately $986 million in additional collateral.

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.

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.

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.

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Our 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 exposures to these various risks is not effective, we could incur significant losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices and could require the maintenance of liquidity resources that would be prohibitively expensive.

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 borrowings. We have significant capital requirements and continued access to debt capital from outside sources is required 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.

Capital 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 capital 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. The decline in the market value of our pension assets experienced in the fourth quarter of 2008 resulted in the need to make additional contributions in 2009 to maintain our funding at sufficient levels. Further significant declines in the market value of these assets may significantly increase our funding requirements for these obligations in the future.

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.

While our generation runs on diverse fuels, allowing for flexibility, the mix of fuels ultimately used can impact earnings. Generation by our coal units in 2009 was adversely affected by 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. This caused a decrease in our coal unit production in 2009 compared to 2008.

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In the event of an accident or acts of war or terrorism, our insurance coverage may be insufficient if we are unable to obtain adequate coverage at commercially reasonable rates.

We have insurance for all-risk property damage including boiler and machinery coverage for our nuclear and non-nuclear generating units, replacement power and business interruption coverage for our nuclear generating units, general public liability and nuclear liability, in amounts and with deductibles that we consider appropriate.

We can give no assurance that this insurance coverage will be available in the future on commercially reasonable terms or that the insurance proceeds received for any loss of or any damage to any of our facilities will be sufficient.

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. 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 generating operating performance.

One of the key elements to achieving the results in our business plans 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, 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG

None.

Power and PSE&G

Not Applicable.

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ITEM 2. PROPERTIES

All of our physical property is owned by our subsidiaries. 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 12. Commitments and Contingent Liabilities.

Generation Facilities

As of December 31, 2009, Power s share of summer installed generating capacity was 15,548 MW, as shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	930	100%	930	Coal/Gas	Load Following
Mercer	NJ	638	100%	638	Coal	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	526	100%	526	Coal/Oil	Base Load/Load Following
New Haven Harbor	CT	448	100%	448	Oil	Load Following
Total Steam		**6,417**		**3,771**		
Nuclear:						
Hope Creek	NJ	1,199	100%	1,199	Nuclear	Base Load
Salem 1 & 2	NJ	2,345	57%	1,346	Nuclear	Base Load
Peach Bottom 2 & 3(B)	PA	2,234	50%	1,117	Nuclear	Base Load
Total Nuclear		**5,778**		**3,662**		
Combined Cycle:						
Bergen	NJ	1,178	100%	1,178	Gas	Load Following
Linden	NJ	1,230	100%	1,230	Gas	Load Following
Bethlehem	NY	746	100%	746	Gas	Load Following
Guadalupe	TX	1,000	100%	1,000	Gas	Load Following
Odessa	TX	1,000	100%	1,000	Gas	Load Following
Total Combined Cycle		**5,154**		**5,154**		
Combustion Turbine:						
Essex	NJ	617	100%	617	Gas	Peaking
Edison	NJ	504	100%	504	Gas	Peaking
Kearny	NJ	446	100%	446	Gas	Peaking
Burlington	NJ	553	100%	553	Oil/Gas	Peaking
Linden	NJ	336	100%	336	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
Bridgeport Harbor	CT	21	100%	21	Oil	Peaking
Total Combustion Turbine		**2,777**		**2,761**		
Pumped Storage:						
Yards Creek(C)	NJ	400	50%	200		Peaking
Total Operating Generation Plants		**20,526**		**15,548**		

(A) Operated by RRI Energy

(B) Operated by Exelon Generation

(C) Operated by JCP&L

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Energy Holdings has investments in the following generation facilities as of December 31, 2009:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used
United States					
Kalaeloa	HI	208	50%	104	Oil
GWF	CA	105	50%	53	Petroleum coke
Hanford L.P. (Hanford)	CA	27	50%	13	Petroleum coke
GWF Energy					
Hanford Peaker Plant	CA	95	50%	48	Natural gas
Henrietta Peaker Plant	CA	97	50%	49	Natural gas
Tracy Peaker Plant	CA	171	50%	85	Natural gas
Total GWF Energy(A)		363		182	
Bridgewater	NH	16	40%	6	Biomass
Conemaugh	PA	15	4%	1	Hydro
Hackettstown	NJ	2	100%	2	Solar
Total United States		**736**		**361**	
International					
Turboven	Venezuela	120	50%	60	Natural gas
Turbogeneradores de Maracay (TGM)	Venezuela	40	9%	4	Natural gas
Total International		**160**		**64**	
Total Operating Power Plants		**896**		**425**	

(A) Under a Memorandum of Understanding to sell. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments.

Transmission and Distribution Facilities

As of December 31, 2009, PSE&G s electric transmission and distribution system included 23,328 circuit miles, of which 7,924 circuit miles were underground, and 822,800 poles, of which 543,313 poles were jointly-owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 2009, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2009, 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 and liquefied natural gas and aggregated 2,973,000 therms (288,640,800 cubic feet on an equivalent basis of 1,030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	773,000
Camden LPG	Camden, NJ	280,000
Central LPG	Edison Twp., NJ	960,000
Harrison LPG	Harrison, NJ	960,000
Total		**2,973,000**

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As of December 31, 2009, PSE&G owned and operated 17,572 miles of gas mains, owned 12 gas distribution headquarters and two subheadquarters, all in three 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, 2009, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 23,173 megavolt-amperes and 246 substations with an aggregate installed capacity of 8,062 megavolt-amperes. In addition, four substations in New Jersey having an aggregate installed capacity of 109 megavolt-amperes were operated on leased property.

ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters 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 12. Commitments and Contingent Liabilities.

Electric Discount and Energy Competition Act (Competition Act)

In 2007, PSE&G and PSE&G Transition Funding LLC (Transition Funding) were served with a copy of a purported class action complaint (Complaint) in the Superior Court of New Jersey, Law Division challenging the constitutional validity of certain provisions of New Jersey s 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. Notice of the filing of the Complaint was also provided to New Jersey s Attorney General. Under New Jersey law, the Competition Act, enacted in 1999, is presumed constitutional. Subsequently the same plaintiff filed an amended Complaint to also seek injunctive relief from continued collection of related taxes, as well as recovery of such taxes previously collected, and also filed a petition with the BPU requesting review and adjustment to PSE&G s recovery of the same charges. We filed a motion to dismiss the amended Complaint (or in the alternative for summary judgment) and we also filed a motion with the BPU to dismiss the petition. In October 2007, our motion to dismiss the amended Complaint was granted. The plaintiff subsequently appealed this dismissal and, on February 6, 2009, the Appellate Division of the New Jersey Superior Court unanimously affirmed the lower court decision. Our motion to dismiss the BPU petition remains pending.

Con Edison (Con Ed)

In 2001, Con Ed filed a complaint with 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. Following extensive discussions, on February 23, 2009, a settlement was filed at FERC resolving all issues in the proceedings and the related proceedings at the D.C. Circuit Court of Appeals. On February 19, 2010, FERC issued an order directing the parties to address certain legal issues before determining whether the settlement can be approved. FERC also reserved the right to establish additional procedures, if needed, and indicated that it would allow further settlement discussions if the parties so desired. The final resolution of this matter cannot be predicted.

Regulatory Proceedings

RPM Auction

In May 2008, several state commissions, including the BPU and consumer advocate agencies, as well as customer groups and certain federal agencies, filed a complaint with FERC against PJM with respect to RPM.

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The complaint challenged the results of the RPM capacity auctions held for the 2008/2009, 2009/2010 and 2010/2011 delivery years. It asserted that various RPM rules permitted suppliers to reduce the amount of capacity offered into the auctions, thereby increasing prices and requested that FERC find that the clearing prices produced are unlawful. FERC issued an order dismissing the complaint in September 2008, and this order was upheld on rehearing.

The BPU and the Maryland Public Service Commission have appealed these FERC orders and this appeal is pending at the U.S. Court of Appeals for the D.C. Circuit. If upheld on appeal, FERC s dismissal of the complaint eliminates the potential for the payment of refunds by suppliers, including Power, with respect to auction payments.

RPM Model

PJM FERC Filing to Prospectively Change Elements of RPM After retaining an outside consultant to prepare a report evaluating the efficacy of the RPM model, PJM submitted a filing at FERC seeking to implement certain prospective changes to RPM. Issues in this proceeding included: the cost of new entry (CONE), the integration of transmission upgrades into RPM modeling, recognition of locational capacity value, participation in RPM by demand-side and energy efficiency resources, penalties for deficiencies and unavailability of capacity resources, and the calculation of avoided cost and long-term contracting to encourage new entry. On February 9, 2009, PJM filed an Offer of Settlement with FERC on behalf of various settling parties. This Offer of Settlement proposed to, among other things, reduce cost of new entry values, eliminate the minimum offer price rule and develop seasonal capacity pricing. We filed comments in opposition to the settlement proposal. FERC issued its order with respect to the Offer of Settlement on March 26, 2009. This order was generally favorable with respect to upholding the RPM market design.

Following an additional stakeholder process that occurred after FERC issued its order, PJM made a compliance filing on September 1, 2009, proposing to implement other findings in the March 26, 2009 order. Notably, PJM proposed a CONE reset mechanism whereby the value would be adjusted annually based on an index and periodically compared against engineering studies and a statistical analysis of new entry bids. In addition, PJM proposed changes to the operation of Incremental Auctions affecting how excess capacity may be released or new capacity needs may be acquired. After FERC issued another order on October 30, 2009, PJM filed another compliance filing on December 29, 2009 in which it further modified the CONE reset mechanism by eliminating the statistical analysis of new entry bids as a benchmark. The December 29, 2009 filing also made further changes to the Incremental Auction mechanism. The changes to the Incremental Auctions are still under review by FERC and certain parties contend that more changes are required. In general, we support PJM s proposal regarding the Incremental Auctions and oppose the additional proposed changes. We cannot predict whether FERC will order additional changes to the Incremental Auction design, but we do not believe that the additional proposed changes would have significant impacts if implemented because they would not directly affect prices in the Base Residual Auction in which most capacity is cleared.

Judicial Appeals In 2007, we filed challenges to the original RPM design in the Court of Appeals for the District of Columbia Circuit relating to the manner in which the CONE was calculated under the tariff at that time. If the CONE is set too low, generators in the PJM markets may not be adequately compensated for existing capacity and may not have sufficient incentives to construct new generating units. The Court of Appeals ultimately rejected our challenge on the grounds that a back-up mechanism for setting the CONE based on engineering studies would address the problems we had identified. The method for setting CONE that was the subject of our appeal was removed from the tariff as part of the prospective changes to RPM discussed above.

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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 U.S. Government alleges damages of approximately $200 million. To PSE&G s knowledge there has been no action on this matter since 1988.

(2) Duane Marine Salvage Corporation Superfund Site is in Perth Amboy, Middlesex County, New Jersey. The EPA had named PSE&G as one of several potentially responsible parties (PRPs) through a series of administrative orders between December 1984 and March 1985. Following work performed by the PRPs, the EPA declared on May 20, 1987 that all of its administrative orders had been satisfied. The NJDEP, however, named PSE&G as a PRP and issued its own directive dated October 21, 1987. Remediation is currently ongoing.

(3) 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.

(4) 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 presents the design details that will implement the EPA s selected remediation remedy. PSE&G s share of the remedy implementation costs is estimated at approximately $4 million.

(5) The Klockner Road site is located in Hamilton Township, Mercer County, New Jersey, and occupies approximately two acres on PSE&G s Trenton Switching Station property. In 1996, PSE&G entered into a memorandum of agreement with the NJDEP for the Klockner Road site pursuant to which PSE&G conducted an RI/FS and remedial action at the site to address the presence of soil and groundwater contamination at the site.

(6) The NJDEP assumed control of a former petroleum products blending and mixing operation and waste oil recycling facility in Elizabeth, Union County, New Jersey (Borne Chemical Co. site) and issued various directives to a number of entities, including PSE&G, requiring performance of various remedial actions. PSE&G s nexus to the site is based upon the shipment of certain waste oils to the site for recycling. PSE&G and certain of the other entities named in the NJDEP directives are members of a PRP group that have been working together to satisfy NJDEP requirements including: funding of the site security program; containerized waste removal; and a site remedial investigation program.

(7) 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.

(8) 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.

(9) In 2004, Exelon Generation signed an agreement for Peach Bottom regarding the DOE s delay in accepting spent nuclear fuel for permanent storage. Under the agreement, Exelon Generation would be reimbursed for costs previously incurred, with future costs incurred resulting from the DOE delays in accepting spent fuel to be reimbursed annually until the DOE fulfills its obligation. In addition, Exelon Generation and Power are required to reimburse the DOE for the previously received credits from the Nuclear Waste Fund. In September 2009, Power signed an agreement with the DOE applicable to Salem and Hope Creek under which we will be reimbursed for past and future reasonable and allowable costs resulting from the DOE s delay in accepting spent nuclear fuel for permanent disposition. For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

(10) 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. We have not yet determined whether the Gates landfill is located on our property or whether we have further obligations with respect to the landfill.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

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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, 2009, there were 86,025 holders of record.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2004 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.

	2004	2005	2006	2007	2008	2009
PSEG	$ 100.00	$ 130.18	$ 137.78	$ 209.33	$ 128.84	$ 153.13
S&P 500	$ 100.00	$ 104.90	$ 121.43	$ 128.09	$ 80.77	$ 102.08
DJ Utilities	$ 100.00	$ 124.95	$ 145.75	$ 174.99	$ 126.37	$ 142.06
S&P Electrics	$ 100.00	$ 117.53	$ 144.74	$ 178.14	$ 132.19	$ 136.61

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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
2009			
First Quarter	$33.66	$23.65	$0.3325
Second Quarter	$33.94	$27.85	$0.3325
Third Quarter	$34.02	$30.38	$0.3325
Fourth Quarter	$34.14	$29.20	$0.3325
2008			
First Quarter	$52.30	$39.08	$0.3225
Second Quarter	$47.28	$40.18	$0.3225
Third Quarter	$47.33	$31.56	$0.3225
Fourth Quarter	$33.72	$22.09	$0.3225

On February 16, 2010, our Board of Directors approved a $0.01 increase in the quarterly common stock dividend, from $0.3325 to $0.3425 per share for the first quarter of 2010. This reflects an indicated annual dividend rate of $1.37 per share.

In July 2008, our Board of Directors authorized the repurchase of up to $750 million of our common stock to be executed over 18 months beginning August 1, 2008. We repurchased 2,382,200 shares of our common stock for $92 million under this authorization. We did not repurchase any shares under this plan during 2009. The authorization expired on February 1, 2010 and has not been renewed.

The following table indicates our common share repurchases during the fourth quarter of 2009:

Fourth Quarter 2009	Total Number of Shares Purchased(A)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plan(B)
				Millions
October 1-October 31		$		$ 658
November 1-November 30	2,000	$ 31.27		$ 658
December 1-December 31	48,000	$ 31.52		$ 658

(A) Represents repurchases of shares in the open market to satisfy obligations under various equity compensation award programs.

(B) Plan expired February 2010 and has not been renewed.

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The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2009:

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	4,122,050	$ 32.10	18,546,808
Equity compensation plans not approved by security holders	20,000	$ 22.93	3,709,649(A)
Total	**4,142,050**	**$ 32.06**	**22,256,457**

(A) Shares issuable under the PSEG Employee Stock Purchase Plan, Compensation Plan for Outside Directors and Stock Plan for outside Directors.

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data Note 17. 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 2009 and Future Outlook.

PSE&G

We own all of the common stock of PSE&G. For additional information regarding PSE&G s ability to continue to pay dividends, see Item 7. MD&A Overview of 2009 and Future Outlook.

On February 16, 2010, PSE&G irrevocably called, for redemption on March 22, 2010, all of its outstanding preferred stock. PSE&G deposited the redemption price and the accrued unpaid dividends to the redemption date, into Bank of New York Mellon shareholder services, terminating all rights of holders of the preferred stock except the right to receive the redemption price upon surrender of shares. As a result all of the outstanding equity is owned by PSEG.

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ITEM 6. SELECTED FINANCIAL DATA

PSEG

The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG

	2009	2008	2007	2006	2005
For the Years Ended December 31:	Millions, where applicable				
Operating Revenues	$ 12,406	$ 13,322	$ 12,677	$ 11,735	$ 11,809
Income from Continuing Operations(A)	$ 1,592	$ 983	$ 1,325	$ 673	$ 842
Net Income	$ 1,592	$ 1,188	$ 1,335	$ 739	$ 661
Earnings per Share:					
Income from Continuing Operations:					
Basic(A)	$ 3.15	$ 1.94	$ 2.61	$ 1.34	$ 1.75
Diluted(A)	$ 3.14	$ 1.93	$ 2.60	$ 1.33	$ 1.72
Net Income:					
Basic	$ 3.15	$ 2.34	$ 2.63	$ 1.47	$ 1.38
Diluted	$ 3.14	$ 2.34	$ 2.62	$ 1.46	$ 1.35
Dividends Declared per Share	$ 1.33	$ 1.29	$ 1.17	$ 1.14	$ 1.12
As of December 31:					
Total Assets	$ 28,730	$ 29,049	$ 28,299	$ 28,508	$ 29,625
Long-Term Obligations(B)	$ 7,679	$ 8,044	$ 8,709	$ 10,147	$ 11,035

(A) Income from Continuing Operations for 2008 includes an after-tax charge of $490 million related to certain leveraged leases. Income from Continuing Operations for 2006 includes an after-tax charge of $178 million related to the sale of an equity method investment.

(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 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 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 U.S.,

- **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 owns our energy-related leveraged leases and other investments.

Our business discussion in Item 1 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. The following expands upon that discussion by describing significant events and business developments that have occurred during 2009 and key factors that we believe will drive our future performance. The following discussion refers to the Consolidated Financial Statements (Statements) and the Related Notes to Consolidated Financial Statements (Notes). This information should be read in conjunction with such Statements and Notes.

OVERVIEW OF 2009 AND FUTURE OUTLOOK

During 2009, our business has been impacted by many factors, including lower gas prices, mild weather, the economic slowdown and increased pension costs resulting from financial market declines experienced in 2008.

The mild weather and the economic slowdown have caused an overall reduction in customer demands for electricity and gas in the markets where we operate. As a result, our generation volumes at Power in 2009 were approximately 5% lower than in 2008. This reduced volume was experienced mainly at our coal facilities as lower gas prices provided an economic advantage to gas-fired generation.

In addition to an overall reduction in customer demand during 2009, we have experienced a higher number of customers choosing to contract with independent electric suppliers rather than remain under the BGS contracts which has negatively affected Power. This migration away from BGS could be sustained or increase if energy prices continue to be lower than the energy price component of the BGS contracts. Migration has resulted and could continue to result in reduced margins as volumes that were previously sold to satisfy obligations under the BGS contracts are replaced with spot market sales at lower prices.

Our distribution operations were also impacted by both the economy and weather conditions in 2009. Our electric delivery volumes for 2009 declined by 4%, 2.5% due to the economy and 1.5% due to a cooler summer in 2009, reflecting a temperature humidity index that was 22% cooler than the summer of 2008. We experienced a 1.1% increase in our gas delivery volumes for 2009 as compared to 2008. Winter weather in 2009, as measured by heating degree days, was 2.4% higher than in 2008, resulting in 1.8% higher gas space heating demand and sales. Economic factors caused a 0.7% drop in gas sales.

Excluding the impact of weather, residential electric and gas volumes were down 0.9% and 0.2% respectively. These declines were in line with our expectations for the impact of the economy on sales to this sector. Residential sales contribute approximately 45% of our electric margin and 75% of our gas margin. Margins from Commercial and Industrial electric customers are not based on total energy consumption as measured by kilowatt-hours, but are based on fixed, monthly demand charges that are set by the highest electric demand for an hour period during the previous 12-month period or, in the case of some electric rates, by the peak demand during the current month. From May through September 2009, the number of hours exceeding 90 degrees was 67% lower than under normal summer weather conditions. This adversely impacted our billed demands,

reducing revenues during the summer months. Commercial and Industrial gas customers also have a significant fixed component to billings. Therefore, any changes in energy usage over comparative periods may not have an equivalent effect on sales margin.

Current economic conditions have also caused deterioration in certain customer payment patterns resulting in a higher portion of our accounts receivable balances remaining outstanding for more than 180 days. This represented 14% of our total customer accounts receivable as of December 2009 as compared to 8% last year. We are focusing our efforts on the oldest and largest accounts to expedite collections. We believe we have sufficient liquidity to manage these delays in customer payments.

Looking forward, continued lower market prices and reduced demands are likely to result in lower margins for our generation business. To help offset these reduced margins we will explore growth opportunities. We have looked, and are continuing to look for ways to reduce costs while maintaining our safety, reliability and environmental standards.

There have also been significant regulatory and legislative developments during the year which may affect our operations in the future as new rules and regulations are adopted.

In March 2009, the Federal Energy Regulatory Commission (FERC) issued an order regarding PJM Interconnection LLC s (PJM) Reliability Pricing Model (RPM). The effect of this order includes an increase in the cost of new entry to more accurately reflect construction and equipment costs. This should incent both new build and continued operation of existing facilities. For additional information, see Part I, Item 3. Legal Proceedings.

In April 2009, the U.S. Supreme Court concluded that the U.S. Environmental Protection Agency (EPA) permissibly relied upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II Section 316(b) regulations of the Federal Water Pollution Control Act. This is important to us because it allows the EPA to continue to use the site-specific cost-benefit test in determining best technology available for minimizing adverse environmental impact. For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities.

In April 2009, the EPA released a proposed finding under the Clean Air Act concluding that CO_2 is one of six types of greenhouse gases (GHG) that cause or contribute to climate change and constitute air pollution which endangers both public health and welfare. Later in 2009, the EPA proposed rules to regulate GHG from motor vehicles. When finalized, by design of the Clean Air Act, rules automatically come into effect which would subject many power generating units, including ours, to Clean Air Act permitting for GHG, including CO_2. The Clean Air Act would require an analysis of the best available control technologies (BACT) whenever a major modification is made with an associated increase in GHG emissions. The technology would have to be applied if available; however, it is unclear what EPA would consider as BACT for GHG at this time. We cannot predict the ultimate resolution of this matter, nor the effect on our operations; however any additional regulation of CO_2 emissions could affect our operations and our ability to renew permits and licenses and could result in additional material compliance costs.

In June 2009, the U.S. House of Representatives passed a bill that promotes renewable energy and requires a reduction in the emission of greenhouse gases from the majority of emission sources, including the generation sector. The bill sets forth major initiatives which include: 1) establishing a national renewable energy standard and 2) creating a market mechanism for the sale and purchase of GHG emission allowances (cap-and-trade program). If enacted in its current form, the bill could reduce or eliminate existing regional inconsistencies in GHG regulations. The Senate has not yet acted, and ultimate enactment into law of a bill with comparable provisions and rules is not certain.

In August 2009, the EPA announced that it is reconsidering whether coal ash, a by-product of generation at our coal facilities, should be regulated as a hazardous waste material. The EPA indicated that it intended to propose a rule by the end of 2009, but has not yet done so. We currently have a

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program at Hudson, Mercer and Bridgeport to beneficially reuse the coal ash as currently allowed by Federal and state regulations. Proposed regulations which more stringently regulate coal ash, including the potential regulation of coal ash as hazardous waste, could materially increase costs for our coal facilities.

During the year, various legislative proposals have been made with the intention of enacting stricter regulation over derivatives in light of the financial market issues experienced last year, largely caused by derivative trading in connection with mortgage loans. It is difficult to predict what the final legislation might contain. If the final legislation required all trading to be done over an exchange, we would expect to see our collateral requirements increase substantially to support our activities.

Our future success will also depend on our ability to respond to the challenges and opportunities presented by these and other regulatory and legislative initiatives.

Operational Excellence

While total generation volumes were down about 5% in 2009, our generating assets continued to perform well. Our lower cost nuclear generation output was 3% higher in 2009 than in 2008.

In addition, our hedging strategy has resulted in higher average realized electric prices which helped to mitigate the effect of reduced generation resulting from recent mild weather and recessionary conditions. The increase in realized prices for 2009 as compared to 2008 was due to comparably higher-priced contracts entered into in prior years that replaced older, lower-priced contracts, such as the 2005 and 2006 Basic Generation Service (BGS) auction contracts which expired in May 2008 and May 2009.

Prices set earlier in 2009 under the most recent RPM auction for the 2012-2013 period were higher than those set for the 2011-2012 period and once again varied based on the constraints in each of the PJM zones, as compared to the uniform zonal pricing set for the periods from June 2010 to May 2012.

On October 1, 2009, ownership of the Texas generation facilities was transferred from Energy Holdings to Power (See Item 8. Financial Statements and Supplementary Data Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies for additional information). Since Power had been responsible for the operation of the Texas facilities under a management agreement since January 2008, there were no operational or commercial impacts resulting from this transaction.

During 2009, PSE&G continued to demonstrate its commitment to maintaining system reliability by achieving top quartile performance in System Interruptions (SAIFI) and Customer Outage Duration (CAIDI) measures.

Energy Holdings remaining portfolio consists primarily of its lease investments at Resources and smaller equity method investments at Global, including GWF Energy which we intend to sell pending necessary approvals. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments for additional information. As a result, Energy Holdings is focused on:

- continuing to reduce our cash tax exposure related to certain leveraged leases by pursuing opportunities to terminate international leases with lessees that are willing to meet certain economic thresholds (See Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities for additional information),

- earning adequate returns on its remaining investments, and

- exploring opportunities for investment in renewable energy products, including solar investments, such as those discussed below, our offshore wind project and compressed air energy storage technology.

Financial Strength

Our businesses continued to generate strong cash from operations in 2009. In addition, Power established a program for the issuance of up to $500 million of unsecured medium-term notes (MTNs) to retail investors and has issued $209 million under this program. We used these funds, cash from operations, and cash on hand to:

contribute $364 million into our qualified pension plans in 2009,

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- pay our maturing debt obligations in 2009 (See Item 8. Financial Statements and Supplementary Data Note 13. Schedule of Consolidated Debt), including the $249 million payment of Parent debt at maturity resulting in the elimination of long term debt at Parent,

- execute a debt exchange between Power and Energy Holdings utilizing $101 million of cash on hand and $303 million of newly issued Power Senior Notes to reduce Energy Holdings Senior Notes to $127 million,

- make an additional $140 million deposit with the IRS to defray potential interest costs associated with the disputed tax liability for the leveraged lease investments, and

- redeem $280 million of non-recourse debt at our Texas plants.

The Board of Directors also approved an increase in the quarterly dividends from $0.3225 per share to $0.3325 per share of Common Stock for each quarter of 2009 resulting in an annual dividend of $1.33 per share. In February 2010, the Board of Directors approved an increase in the first quarter dividend from $0.3325 per share to $0.3425 per share of Common Stock. This increase was consistent with maintaining our target payout ratio of 40% to 50% of Operating Earnings.

We believe that our strong operations and strong financial position will continue to allow us to manage through the current economic conditions. We expect that our cash from operations, when combined with cash on hand, will be the primary source used to:

- support our projected capital expenditure program,

- fund shareholder dividends,

- fund contributions to our pension plans, and

- provide for potential payments to address income tax claims related to our leveraged lease transactions, discussed in Note 12. Commitments and Contingent Liabilities.

Any funds remaining after satisfying these obligations, when combined with potential additional financing capacity, would be discretionary cash that could be used to invest in the business or reduce debt.

Disciplined Investment

We expect to continue to invest in areas that complement our existing businesses and provide attractive risk-adjusted returns. These areas include responding to climate change, upgrading critical energy infrastructure and providing new energy supplies in markets with growing demand. We also have several projects where we are investing to continue to improve our operational performance and meet environmental commitments. During 2009:

- We were assigned construction and operating responsibility for an additional 500 kV transmission project in New Jersey that would run from Branchburg to Hudson. In December 2009, FERC granted PSE&G s request for incentive rate treatment. This project is still in the design phase and would require the receipt of numerous regulatory approvals prior to construction.

We are continuing to pursue obtaining all necessary regulatory approvals for the $750 million Susquehanna-Roseland transmission project. We are awaiting numerous regulatory approvals for this project, although on February 11, 2010, the BPU granted approval to PSE&G to construct the New Jersey portion of the project. We cannot predict the outcome of the regulatory approvals that are still pending.

We received approval from the BPU for a new solar loan program, called Solar Loan II. Under Solar Loan II, we would help finance the installation of an additional 51 MW of solar-powered generating systems in our electric service territory. The remaining financing capacity from our current solar loan program will be rolled into this new program.

The BPU approved our Solar 4 All Program. Under this program, we anticipate investing approximately $515 million to develop 80 MW of utility-owned solar photovoltaic systems over four years. Total expenditures through December 31, 2009 related to this project were approximately $13 million.

The BPU approved our Capital Economic Stimulus Program. Under this program, we anticipate accelerating $694 million of capital infrastructure investments through our distribution business in New Jersey over a 24-month period. The program seeks to support employment in New Jersey, while enhancing reliability. This program provides for a charge for contemporaneous recovery of a return on the program expenditures plus depreciation of the assets which will be adjusted each January. Total expenditures through December 31, 2009 related to this project were approximately $180 million.

The BPU approved our Energy Efficiency Economic Stimulus Program. Under this program, we anticipate approximately $190 million in energy efficiency expenditures in New Jersey over an 18-month period. The program seeks to help New Jersey meet its Energy Master Plan goal of reducing energy consumption by 20% by 2020 and to support employment growth. This program provides for a charge for contemporaneous recovery of a return on the program expenditures. Total expenditures through December 31, 2009 related to this project were approximately $5 million.

We continued construction of back end technology at our Mercer and Hudson stations and completed construction of back end technology at our Keystone station to meet our environmental commitments (see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities for additional information).

We began construction of a steam path retrofit and related upgrades at Peach Bottom with a total anticipated cost of $192 million. Approximately $27 million has been spent as of December 2009. These upgrades are expected to result in an increase of our share of capacity by 32 MW (14 MW at Unit 3 in 2011 and 18 MW at Unit 2 in 2012). We also anticipate expenditures in pursuit of additional output through an extended power uprate at Peach Bottom. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Our share of the increased capacity is expected to be 133 MW with an anticipated cost of approximately $400 million.

In connection with our exploration of new nuclear development, we continue to prepare 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. We anticipate submitting the application to the NRC for the ESP in the first half of 2010. Total expenditures through December 31, 2009 related to this project were approximately $18 million.

We plan to construct 178 MW of gas-fired peaking capacity at our Kearny site. This capacity was bid and cleared the PJM RPM base residual capacity auction for the 2012-2013 period. We expect to begin construction in the second quarter of 2011. The project is expected to be in-service by June 2012. We estimate the cost of these generating units to be $160 million to $200 million, with approximately $8 million spent as of December 2009.

We also plan to construct 130 MW of gas-fired peaking capacity in Connecticut for an estimated cost of $130 million to $140 million. The project has been approved and we expect to begin construction in June 2011. The project is expected to be in service by June 2012. Total expenditures through December 2009 related to this project were $13 million.

We developed a solar project in New Jersey and have acquired two additional solar projects currently under construction in Florida and Ohio. The three together have a total capacity of approximately 29 MW. Completion of these projects is expected by the end of 2010 with a total investment of approximately $114 million.

There is no guarantee that these or future initiatives will be achieved since many issues need to be favorably resolved, such as system conditions, regulatory approvals and funding of construction or development costs.

We receive immediate recovery of our transmission investments and costs through our FERC-approved formula transmission rate. The formula rate mechanism provides for an annual setting of our transmission rates as well as an annual true up to ensure timely recovery of the actual costs of providing transmission service and PSE&G s approved return on equity. In accordance with our formula rate protocols, in October 2009, we filed our 2010 Annual Formula Rate Update with FERC. The rates became effective on January 1, 2010. On

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February 2, 2010 FERC issued an order accepting our filing. The update provides for approximately $23 million in increased revenues as part of our 2010 transmission rates.

In January 2010, we filed an updated Petition with the BPU for an increase in electric and gas distribution base rates. The amounts requested were $148 million and $74 million for electric and gas respectively. The matter is pending with a decision expected in the first half of 2010.

We anticipate that any current spending under the Capital Economic Stimulus Program will be included in our rate base with the expected decision in our Base Rate Case and that we will continue to receive contemporaneous recovery of future expenditures under this program with the return on equity adjusted to reflect the rate allowed in the Base Rate Case. The recovery mechanisms approved by the BPU for our Solar 4 All, Solar Loan, Energy Efficiency and Demand Response programs are scheduled to be reset on January 1st of each year, with the return on equity to be adjusted to reflect the rate allowed in the Base Rate Case at the time of the BPU Order.

RESULTS OF OPERATIONS

Earnings (Losses) In Millions	**Years Ended December 31,**	**2009**	**2008**	**2007**
Power		$ 1,189	$ 1,115	$ 1,000
PSE&G		325	364	380
Energy Holdings(A)		72	(468)	12
Other(B)		6	(28)	(67)
PSEG Income from Continuing Operations		**1,592**	**983**	**1,325**
Income from Discontinued Operations, Including Gain on Disposal(C)			205	10
PSEG Net Income		**$ 1,592**	**$ 1,188**	**$ 1,335**

Earnings Per Share (Diluted)	**Years Ended December 31,**	**2009**	**2008**	**2007**
PSEG Income from Continuing Operations		**$ 3.14**	**$ 1.93**	**$ 2.60**
Income from Discontinued Operations, Including Gain on Disposal(C)			0.41	0.02
PSEG Net Income		**$ 3.14**	**$ 2.34**	**$ 2.62**

(A) Energy Holdings results include after-tax charges of $490 million taken in 2008 related to leveraged lease transactions, the reversal of $29 million, after-tax, of that reserve in 2009 and $23 million of after-tax loss resulting from the sale of Chilquinta and Luz del Sur (LDS) in 2007.

(B) Other includes parent company interest and financing costs, donations, certain administrative and general expenses and certain consolidating entries related to the debt exchange between Power and Energy Holdings.

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

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Our results include the realized gains, losses and earnings on Power s NDT Funds and other related activity. This includes the net realized gains and other-than-temporary impairments, as well as interest and dividend income and other costs related to the NDT Funds which are recorded in Other Income and Deductions. This also includes the interest accretion expense on Power s nuclear asset retirement obligation, which is recorded in Operation and Maintenance Expense and the Depreciation expense related to the asset retirement obligation. The combined after-tax impact on earnings of this activity for the years ended December 31, 2009, 2008 and 2007 is shown in the chart below along with the after-tax impacts of mark-to-market (MTM) activity:

	In Millions, after tax		
	2009	**2008**	**2007**
NDT Fund Activity	$ 9	$ (71)	$ 12
Non-Trading Mark-to-Market Gains (Losses)	$ (25)	$ 16	$ 10

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding changes related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, donations and general and administrative costs at the parent company. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data Note 22. Related-Party Transactions.

	For the Years Ended December 31,			Increase / (Decrease) 2009 vs 2008		Increase / (Decrease) 2008 vs 2007	
	2009	**2008**	**2007**	Millions	%	Millions	%
		Millions					
Operating Revenues	$ 12,406	$ 13,322	$ 12,677	$ (916)	(7)	$ 645	5
Energy Costs	5,711	7,295	6,512	(1,584)	(22)	783	12
Operation and Maintenance	2,603	2,486	2,406	117	5	80	3
Depreciation and Amortization	838	792	774	46	6	18	2
Income from Equity Method Investments	39	37	115	2	5	(78)	(68)
Gain (Loss) on Disposal of and (Impairment) on Equity Method Investments	(22)	(27)	137	5	(19)	(164)	N/A
Other Income and Deductions	86	100	91	(14)	(14)	9	10
Other-Than-Temporary Impairments	61	220	73	(159)	(72)	147	201
Interest Expense	527	594	727	(67)	(11)	(133)	(18)
Income Tax Expense	1,044	926	1,064	118	13	(138)	(13)
Income from Discontinued Operations, including Gain on Disposal, net of tax		205	10	(205)	(100)	195	N/A

The 2009 year-over-year increase in our Income from Continuing Operations reflects the following:

Absence of after-tax charges of $490 million recorded in 2008 associated with deductions taken for tax purposes on certain types of leveraged lease transactions at Energy Holdings that are being challenged by the IRS. See Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities for additional information.

Earnings were higher at Power due to lower other than temporary impairments on investments in the NDT Funds, higher prices realized under sales contracts and lower generation costs, and lower interest expense, partially offset by lower sales volumes, higher depreciation expense and higher pension expense.

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Earnings were higher at Energy Holdings due to gains on sales and terminations of leveraged lease assets, partially offset by lower income due to assets sold.

Earnings were lower at PSE&G due primarily to lower customer demand and higher pension expense.

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

Power

As discussed in Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies, Power s results have been retrospectively adjusted to include the earnings related to Texas for prior periods.

	For the Years Ended December 31,			Increase / (Decrease)	Increase / (Decrease)
	2009	**2008**	**2007**	**2009 vs 2008**	**2008 vs 2007**
			Millions		
Income from Continuing Operations	$ 1,189	$ 1,115	$ 1,000	$ 74	$ 115
Loss from Discontinued Operations, net of tax			(8)		(8)
Net Income	$ 1,189	$ 1,115	$ 992	$ 74	$ 107

For the year ended December 31, 2009, the primary reasons for the increase in Income from Continuing Operations were

lower fuel costs and higher pricing under our BGS and other contracts partially offset by lower generation,

lower other-than-temporary impairments and lower net losses on investments in the NDT Funds,

lower maintenance costs due to higher planned outage work in 2008 partially offset by higher pension costs in 2009, and

lower interest expense due to higher capitalization of interest related to projects in 2009,

partially offset by higher depreciation due to additional assets placed in service in 2009.

Included is the recognition of non-trading MTM losses of $25 million, after-tax, in 2009 as compared to $16 million of after-tax MTM gains in 2008.

For the year ended December 31, 2008, the primary reasons for the increase in Income from Continuing Operations were higher prices and sales volumes on BGS contracts and in the various power pools, partially offset by higher generation costs, and

higher prices on a reduced sales volume under the BGSS contract due to customer conservation and a milder winter heating season in 2008,

partially offset by net losses on investments in the NDT Funds.

Included is the recognition of non-trading MTM gains of $16 million, after-tax, in 2008 as compared to $10 million of after-tax MTM gains in 2007.

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

	For the Years Ended December 31,			Increase / (Decrease)			Increase / (Decrease)		
Power	**2009**	**2008**	**2007**	**2009 vs 2008**			**2008 vs 2007**		
	Millions				Millions	%		Millions	%
Operating Revenues	$ 7,143	$ 8,483	$ 7,422	$	(1,340)	(16)	$	1,061	14
Energy Costs	3,740	5,051	4,414		(1,311)	(26)		637	14
Operation and Maintenance	1,114	1,126	1,061	$	(12)	(1)	$	65	6
Depreciation and Amortization	203	181	158		22	12		23	15
Other Income and (Deductions)	99	100	145	$	(1)	(1)	$	(45)	(31)
Other-Than -Temporary Impairments	60	219	73		(159)	(73)		146	200
Interest Expense	167	192	185	$	(25)	(13)	$	7	4
Income Tax Expense	769	699	676		70	10		23	3
Loss from Discontinued Operations, net of tax			(8)	$		N/A	$	8	100

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For the year ended December 31, 2009 as compared to 2008

Operating Revenues decreased $1,340 million due to

Generation revenues decreased $733 million due to

- lower revenues of $609 million resulting from lower volumes of generation sold at lower prices in PJM, ERCOT and the NY power pool and lower prices on a higher volume of generation sold in the ISO-NE, partially offset by favorable results from financial hedging transactions,
- a net decrease of $146 million due to a lower volume of BGS contracts partially offset by higher prices, and
- a decrease of $51 million due to lower ancillary services revenues and auction revenue rights as well as the absence of a damage claim awarded by the federal government in 2008,
- partially offset by higher revenues of $60 million due to several new wholesale contracts entered into in 2009 and repricing of certain wholesale contracts, and
- $14 million of higher capacity payments largely due to changes in PJM s capacity market.

Gas Supply revenues decreased $622 million

- including a net decrease of $436 million resulting from sales under the BGSS contract, substantially comprised of lower average gas prices in 2009 net of gains on financial hedging transactions on a volume of sales nearly unchanged from that in 2008, and
- a net decrease of $186 million due to lower prices on a reduced sales volume to third party customers.

Trading revenues increased $15 million due primarily to gains on electric-related contracts.

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 by $1,311 million due to

- **Generation costs** decreased by $696 million due to $952 million of lower fossil fuel costs, primarily reflecting lower average natural gas prices and lower volumes of natural gas and coal purchases, partly offset by $21 million of higher nuclear fuel costs, net losses of $110 million from financial hedging transactions, $44 million for increased power purchases, $33 million for CO_2 allowances and environmental technology and fees, $18 million for higher purchases of financial transmission rights and $16 million for cancellation charges on cancelled coal shipments.

¡ **Gas costs** decreased $615 million, reflecting net decreases of $434 million and $181million related to Power s obligations under the BGSS contract and sales to third party customers respectively, reflecting lower inventory costs.

Operation and Maintenance decreased $12 million due primarily to

¡ a net decrease of $85 million due to lower planned maintenance costs and the absence of expense for planned outages in 2008 at our fossil stations,

¡ partially offset by $19 million related to additional staffing and salary increases, a planned outage at Peach Bottom and Hope Creek in 2009 and preventative maintenance costs at all our nuclear stations, and

¡ an increase in pension expense of $55 million.

Depreciation and Amortization increased $22 million due to

¡ an increase of $18 million due to pollution control equipment being placed into service in December 2008 at our Mercer 1 and 2 generating facilities and in October 2009 at our Keystone generating facility, and

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- an increase of $10 million resulting from larger depreciable asset bases for fossil and nuclear in 2009,
- partially offset by a $4 million related to the reimbursement of previously capitalized storage costs for spent nuclear fuel resulting from a favorable settlement in September 2009 for reimbursement of such costs by the U.S. Department of Energy.

Other Income and Deductions Net Other Income decreased $1 million due primarily to

a decrease of $8 million in interest income, dividends and fees related to the NDT Funds, and

a write-off of $5 million due to the early retirement of obsolete pollution control equipment,

partially offset by an increase in net gains of $14 million on the NDT Fund securities.

Other-Than-Temporary Impairments decreased $159 million due to the lower charges in 2009 related to the NDT Fund securities.

Interest Expense decreased $25 million due to

higher capitalized interest of $14 million in 2009 due primarily to installation of back-end pollution-control technology at Fossil and projects at Nuclear in 2009, and

lower interest expense of $29 million due to the maturity of $250 million of 3.75% Notes in April 2009 and redemption of Texas project loans in February 2009,

partially offset by $17 million of higher interest expense in 2009 related to the issuance of $209 million of medium-term notes in January 2009 and $303 million of notes issued in September 2009 as part of a debt exchange with Energy Holdings.

Income Tax Expense increased $70 million in 2009 due primarily to

an increase of $59 million due to higher pre-tax income and $17 million due to higher earnings from the NDT Funds,

$22 million due to decreased benefits from a manufacturing deduction under the American Jobs Creation Act of 2004, and $10 million due to an increase in state taxes,

partially offset by $32 million from the reduction of the reserve for uncertain tax positions and $6 million related to prior years book versus tax return timing adjustments.

For the year ended December 31, 2008 as compared to 2007

Operating Revenues increased $1,061 million due to

Generation revenues increased $882 million due to

- higher revenues of $446 million resulting from a higher volume of generation being sold at higher prices into PJM and ISO-NE and higher prices on lower volumes of sales in ERCOT and the New York power pools, partially offset by net losses on financial hedging transactions,
- a net increase of $355 million from higher prices on a higher volume of BGS contracts modestly offset by the expiration of several contracts in May 2008,
- $67 million from higher capacity prices resulting from the changes in the capacity markets in PJM, New York and Connecticut, and
- $32 million for ancillary and other services as well as a damage claim awarded by the federal government for an oil spill in the Delaware River in 2004.

Gas Supply revenues increased $156 million

- including $130 million resulting from sales under the BGSS contract due to higher average gas prices in 2008, partly offset by lower sales volumes due to customer conservation and milder winter temperatures in 2008, and

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- a net increase of $27 million due to higher prices on sales to third party customers on a reduced sales volume.

Trading revenues increased $23 million principally due to gains on electric-related contracts and contracts related to financial transmission rights.

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 increased by $637 million due to

- **Generation costs** increased by $466 million due to $509 million of higher fuel costs related to higher prices and higher volumes of natural gas and $17 million of higher costs of energy purchases reflecting higher prices, partly offset by net gains of $67 million from financial hedging transactions.

- **Gas costs** increased $171 million, reflecting net increases of $150 million and $20 million related to Power s obligations under the BGSS contract and sales to third party customers, respectively, reflecting higher inventory costs partially offset by reduced volumes.

Operation and Maintenance increased $65 million due primarily to

- a net increase of $49 million due to planned outages and higher maintenance costs at our fossil stations, primarily Hudson and Linden,

- an increase of $10 million related to planned outages at the Peach Bottom and Salem stations, and

- an increase of $6 million in asset management fees and salaries at the Texas plants.

Depreciation and Amortization increased $23 million due to

- an increase of $14 million resulting from a larger depreciable nuclear and fossil asset base in 2008, and

- an increase of $9 million due to depreciation of pollution control equipment being placed into service at our Bridgeport generating facility.

Other Income and Deductions Net Other Income decreased $45 million due to

net losses of $19 million on the NDT Fund derivative instruments,

- lower interest income of $13 million from short-term loans to our parent company, and
- a $13 million charge for the purchase of net operating loss carryforwards under the State of New Jersey Tax Benefit Purchase Program.

Other Than Temporary Impairments increased $146 million related to the NDT Fund securities.

Interest Expense increased $7 million due primarily to the issuance of $40 million of 5.75% Pollution Control Bonds due 2037 in November 2007 and $44 million of 4.00% Pollution Control Bonds due 2042 in December 2007.

Income Tax Expense increased $23 million in 2008 due primarily to

- an increase of $53 million due to higher pre-tax income,
- partially offset by a reduction of $16 million due to lower earnings from the NDT Funds, and
- a reduction of $9 million due to increased benefits from a manufacturing deduction under the American Jobs Creation Act of 2004.

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PSE&G

	For the Years Ended December 31,			Increase / (Decrease)	Increase / (Decrease)
	2009	2008	2007	2009 vs 2008	2008 vs 2007
			Millions		
Income from Continuing Operations	$ 325	$ 364	$ 380	$ (39)	$ (16)
Net Income	$ 325	$ 364	$ 380	$ (39)	$ (16)

For the year ended December 31, 2009, the primary reasons for the decrease in Income from Continuing Operations were

lower revenues due to lower customer demand resulting from current economic conditions, and

higher Operation and Maintenance expense, primarily increased pension expense,

partially offset by a transmission formula rate increase.

For the year ended December 31, 2008, the primary reasons for the decrease in Income from Continuing Operations were

lower revenues due to lower customer demand resulting from current economic conditions, and

lower electric and gas sales volumes due to a milder winter heating season,

partially offset by tax adjustments related to an IRS refund and other tax items.

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

	For the Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
PSE&G	2009	2008	2007	2009 vs 2008		2008 vs 2007	
		Millions		Millions	%	Millions	%
Operating Revenues	$ 8,243	$ 9,038	$ 8,493	$ (795)	(9)	$ 545	6
Energy Costs	5,170	6,072	5,498	(902)	(15)	574	10
Operation and Maintenance	1,474	1,338	1,308	136	10	30	2
Depreciation and Amortization	608	583	591	25	4	(8)	(1)
Other Income and (Deductions)	5	8	12	(3)	(38)	(4)	(33)
Interest Expense	312	325	332	(13)	(4)	(7)	(2)
Income Tax Expense	226	228	257	(2)	(1)	(29)	(11)

For the year ended December 31, 2009 as compared to 2008

Operating Revenues decreased $795 million due primarily to

Delivery Revenues increased $30 million due primarily to an increase in prices for electric distribution and transmission partially offset by a decrease in electric distribution. Gas distribution was up due to both higher volumes and lower prices.

Electric distribution revenues were down $23 million due primarily to lower sales volumes of $63 million partially offset by rate increases of $40 million. The volumes were down due to weather and economic conditions. The current economic slowdown reduced volumes as customers cut back on use of air conditioning to save money. Rates were up due to an increase in Regional Greenhouse Gas Initiative (RGGI) revenues and stimulus rates.

Transmission revenues were up $37 million due primarily to net rate increases.

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Gas distribution revenues were up $16 million due to higher sales volumes of $6 million, RGGI revenues of $4 million and stimulus rates of $6 million.

Other Operating Revenues increased $10 million due primarily due an increase in our appliance repair business.

Clause Revenue, primarily the Societal Benefits Charges (SBC), increased $67 million, which is entirely offset by the amortization of related costs (Regulatory Assets) into the Operation and Maintenance accounts, and the Depreciation and Amortization accounts. PSE&G earns no margins on SBC collections. For more information, see the discussion of State Regulation in Part I, Item 1 Regulatory Issues.

Commodity Revenue decreased $902 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 $479 million primarily due to $355 million in lower BGS revenues, and $167 million in lower non-utility generation (NUG) revenue due primarily to lower prices, partially offset by $43 million in higher NGC revenue. BGS sales were down 14% primarily due to large customer migration to Third Party Suppliers (TPS), in contrast delivery sales were only down 4% due to the weather and economic conditions.

Gas revenues decreased $423 million due to decreased BGSS prices $365 million and lower commercial and industrial sales due to economic conditions $70 million, offset by higher sales to residential customers $12 million. The average price of gas was 16% lower in 2009 than 2008.

Energy Costs decreased $902 million. This is entirely offset by Commodity revenue. Details are as follows:

Gas costs decreased $423 million due to $365 million or 16% in lower prices and by $58 million or 3% in lower sales volumes due primarily to economic conditions.

Electric costs decreased $479 million due to $487 million or 13% in lower BGS and NUG volumes due to large customer migration to TPS, weather and economic conditions offset by $8 million in higher BGS and NUG prices.

Operation and Maintenance increased $136 million primarily due to

$69 million of higher labor and benefits, primarily increased pension expense,

increases in electric and gas SBC expenses of $61 million, and

higher expenses related to RGGI and Capital Adjustment Charges (CAC) of $21 million,

partially offset by lower material usage of $11 million and a lower gas bad debt expense of $3 million.

Depreciation and Amortization increased $25 million due to

increases of $12 million for amortization of regulatory assets,

$8 million additional plant in service, and $5 million in software amortization.

Other Income and Deductions Net Other Income decreased $3 million due to $4 million in lower investment income resulting from current market conditions, partially offset by a $1 million in solar loan interest.

Interest Expense decreased by $13 million due primarily to lower average debt balances.

Income Tax Expense decreased by $2 million due primarily to lower pretax income, offset by $17 million tax benefits taken in 2008 related to an IRS refund.

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For the year ended December 31, 2008 as compared to 2007

Operating Revenues increased $545 million due primarily to

Delivery Revenues decreased $40 million due primarily to an lower sales volumes for electric distribution, transmission and gas distribution.

Electric distribution revenues were down $22 million due primarily to lower sales volumes of $31 million partially offset by rate increases of $9 million. The volumes were down due to mild weather and economic conditions.

Transmission revenues were down $13 million due a lower transmission peak offset by a rate increase of $4 million.

Gas distribution revenues were down $9 million due to lower sales volumes resulting from mild weather and economic conditions.

Other Operating Revenues decreased $6 million primarily due to lower appliance service sales.

Clause Revenue, primarily the SBC, increased $17 million, which is entirely offset by the amortization of related costs (Regulatory Assets) into the Operation and Maintenance accounts, and also into the Depreciation and Amortization accounts. PSE&G earns no margins on SBC collections. For more information, see the discussion of State Regulation in Part I, Item 1 Regulatory Issues.

Commodity Revenue increased $574 million due to higher 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 increased $432 million primarily due to $491 million in higher prices for BGS, and $75 million in higher NUG prices, partially offset by $112 million for lower BGS volumes, and $21 million due to lower NUG volumes and lower NGC prices.

Gas revenues increased $142 million due to $234 million for increased BGSS prices offset by $92 in lower sales volumes due to weather and economic conditions.

Energy Costs increased $574 million. This is entirely offset by Commodity revenue.

Gas costs increased $142 million due to $234 million or 9% in higher prices partially offset by $92 million or 4% in lower sales volumes due to weather and economic conditions.

Electric costs increased $432 million due to 17% in higher prices for BGS and NUG purchases $552 million, partially offset by 4% in lower BGS volumes due to weather and economic conditions $121 million.

Operation and Maintenance increased $30 million primarily due to

increases in electric SBC expenses of $42 million offset by lower gas SBC expenses $6 million, and

higher bad debt expense $8 million,

- partially offset by lower injuries and damages of $8 million, and
- decreased payroll and fringe benefits $8 million.

Depreciation and Amortization decreased $8 million due to

- decrease of $10 million for amortization of regulatory assets,
- $5 million in software amortization, and
- $5 million in amortization of DOE enrichment facility decommissioning costs,
- partially offset by $12 million additional plant in service.

Other Income and Deductions Net Other Income decreased $4 million due to

- $7 million in lower investment income due to market conditions,
- partially offset by a $3 reduction in income tax on contributions in aid of construction (CIAC).

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Interest Expense decreased by $7 million due primarily to lower average debt balances.

Income Tax Expense decreased by $29 million due primarily to $18 million on lower pretax income, and $17 million tax benefits related to an IRS refund.

Energy Holdings

	For the Years Ended December 31,			Increase / (Decrease)	Increase / (Decrease)
	2009	2008	2007	2009 vs 2008	2008 vs 2007
	Millions				
Income (Loss) from Continuing Operations	$ 72	$ (468)	$ 12	$ 540	$ (480)
Income from Discontinued Operations, including Gain on Disposal, net of tax		205	18	(205)	187
Net Income (Loss)	$ 72	$ (263)	$ 30	$ 335	$ (293)

For the year ended December 31, 2009, the primary reasons for the increase in Income from Continuing Operations were

the absence of a $490 million, after-tax, charge on leveraged leases in 2008 and the reduction of $29 million, after-tax, of that reserve in 2009, and

gains on the sales and terminations of leveraged lease assets,

partially offset by lower leveraged lease revenues due primarily to the sale of leveraged lease assets,

the premium paid on the debt exchange with Power, and

the absence of benefits recorded in 2008 related to an IRS refund claim.

For the year ended December 31, 2008, the primary reasons for the decrease in Income from Continuing Operations were

the charge on leveraged leases recorded in the second quarter in 2008, and

the absence of income from Chilquinta and LDS which were sold in 2007,

partially offset by lower interest expense due to debt retirement and lower premium on bond redemption, and tax adjustments related to an IRS refund.

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

Energy Holdings	For the Years Ended 2009	2008	2007	Increase / (Decrease) 2009 vs 2008 Millions	%	Increase / (Decrease) 2008 vs 2007 Millions	%
	Millions						
Operating Revenues	$ 221	$ (368)	$ 167	$ 589	N/A	$ (535)	N/A
Operation and Maintenance	47	57	66	(10)	(18)	(9)	(14)
Depreciation and Amortization	11	11	12			(1)	(8)
Income from Equity Method Investments	39	36	115	3	8	(79)	(69)
Gain (Loss) on Disposal of and (Impairment) on Equity Method Investments	(22)	(27)	137	(5)	(19)	(164)	N/A
Other Income and (Deductions)	(27)	25	(28)	(52)	N/A	53	N/A
Interest Expense	37	57	125	(20)	(35)	(68)	(54)
Income Tax Expense	45	9	176	36	N/A	(167)	N/A
Income from Discontinued Operations, including Gain (Loss) on Disposal, net of tax	$	$ 205	$ 18	$ (205)	(100)	$ 187	N/A

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For the year ended December 31, 2009 as compared to 2008

Operating Revenues increased $589 million due primarily to

- the absence of a $485 million charge on leveraged leases in 2008, and
- a $158 million increase due to sales and terminations of leveraged lease assets and other investments,
- partially offset by lower leveraged lease revenues of $29 million due primarily to the sale of leveraged lease assets and
- a $25 million charge recorded in December 2009 due to a change in the timing of projected cash flows related to our leveraged leases.

See Note 12. Commitments and Contingent Liabilities for additional information.

Operation and Maintenance decreased $10 million due primarily to lower outside service costs, wages, salaries and benefits.

Income from Equity Method Investments experienced no material change.

Gain (Loss) on Disposal of and Impairment on Equity Method Investments Net impairments decreased $5 million due to the absence of the impairment on PPN recorded in 2008 which was partially offset by the impairment of GWF in 2009.

Other Income and (Deductions) Net Other Deductions increased $52 million due primarily to a premium paid on the debt exchange with Power.

Interest Expense decreased $20 million due primarily to lower debt balances following the debt exchange with Power.

Income Tax Expense increased $36 million due primarily to $93 million related to the sale of leverage lease and other assets in 2009, partially offset by a $57 million decrease on the reserve for unrecognized taxes.

Income from Discontinued Operations, including Gains on Disposal, net of tax

During 2008, we sold our investments in SAESA Group and Bioenergie. Income from Discontinued Operations relating to these investments for the year ended December 31, 2008 totaled $205 million. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments for additional information.

For the year ended December 31, 2008 as compared to 2007

Operating Revenues decreased $535 million due primarily to

- a $485 million charge on leveraged leases in 2008, and
- a $38 million decrease in leveraged lease income, due to lease adjustments.

Operation and Maintenance decreased $9 million due primarily to lower outside service costs, wages, salaries and benefits.

Depreciation and Amortization experienced no material change.

Income from Equity Method Investments decreased $79 million due primarily to

- the absence of earnings of $65 million from Chilquinta and LDS which were sold in 2007, and
- $7 million in lower income from GWF due to higher fuel costs and lower generation.

Gain (Loss) on Disposal of and Impairment on Equity Method Investments decreased $164 million due to

- the absence of $153 million pre-tax gain on the sale of equity investments in 2007, and
- $11 million in higher write-downs of investment in PPN and Turboven in 2008 as compared to 2007.

Other Income and (Deductions) Net Other Income increased $53 million due primarily to

- the absence of a $46 million loss on the early retirement of debt resulting from the December 2007 redemption of Energy Holdings 10% Senior Notes due 2009, and
- $6 million of higher interest and dividend income.

Interest Expense decreased $68 million due primarily to lower debt balances.

Income Tax Expense decreased $167 million due primarily to

- the absence of $163 million of taxes recorded as a result of the sale of Chilquinta and LDS in 2007, and
- $37 million of lower adjustments to the reserve for unrecognized tax benefits,
- partially offset by $14 million in higher taxes on pre-tax income and $18 million of federal and state audit adjustments for prior years paid in 2008.

Income from Discontinued Operations, including Gains on Disposal, net of tax

During 2008, we sold our investments in SAESA Group and Bioenergie. During 2007, we sold our investment in Electroandes. Income from Discontinued Operations relating to these investments for the years ended December 31, 2008 and December 31, 2007 totaled $205 million and $18 million, respectively. See Item 8. Financial Statements and Supplementary Data Note 4. Discontinued Operations, Dispositions and Impairments for additional information.

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

Our capital requirements are met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt and equity for capital investments.

PSE&G s sources of external liquidity include a $600 million multi-year syndicated credit facility as well as bilateral credit agreements. PSE&G s $600 million 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 with PSEG or any other affiliate. PSE&G s dividend payments to PSEG are consistent with its capital structure objectives which have been established to maintain solid 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 Services participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Energy Holdings has historically lent to the money pool; its primary source of liquidity is its invested balance with PSEG. PSEG s sources of external liquidity include a $1.0 billion multi-year syndicated credit facility as well as bilateral credit agreements. These facilities are available to back-stop PSEG s $1.0 billion commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to Power for the issuance of letters of credit. PSEG s credit facilities and the $1 billion 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 $1.95 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 the parent are also designed to be consistent with its capital structure objectives which have been established to achieve solid investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues either retail medium-term notes or senior unsecured debt to raise long-term capital.

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Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2009, our operating cash flow decreased by $490 million. For the year ended December 31, 2008, our operating cash flow increased by $424 million. The net changes were due to net changes from our subsidiaries as discussed below.

Power

Power s operating cash flow decreased $148 million from $1,806 million to $1,658 million for the year ended December 31, 2009, as compared to 2008, primarily resulting from

- a decrease of $350 million in net cash collateral receipts,
- a decrease of $144 million from net payments of counterparty payables,
- $94 million in increased pension fund contributions and related payments in 2009,
- partially offset by a $260 million net decrease in spending on fuel inventories resulting from reduced pricing and demands,
- a $103 million increase from net collections of counterparty receivables, and
- a $69 million increase in deferred income taxes due to bonus depreciation and an increase in planned pension contributions.

Power s operating cash flow increased $541 million from $1,265 million to $1,806 million for the year ended December 31, 2008, as compared to 2007, primarily resulting from

- an increase of $400 million in net cash collateral receipts,
- an increase of $113 million from net collections of counterparty receivables, and
- an increase in net income of $123 million, which includes $163 million of higher net losses in 2008 as compared to 2007,
- partially offset by a $201 million net increase in spending on fuel inventories resulting from reduced pricing and demands.

PSE&G

PSE&G s operating cash flow increased $44 million from $913 million to $957 million for the year ended December 31, 2009, as compared to 2008, due primarily to

$171 million in higher collections of customer receivables,

increases of $108 million in deferred income taxes related to bonus depreciation and increased planned pension contributions, and

$90 million in higher recovery of deferred energy costs,

partially offset by $180 million in increased pension fund contributions and related payments,

decreases of $94 million in accounts payable and obligation to return cash collateral due primarily to lower electric and gas payables, and

$53 million in higher prepaid state sales taxes.

PSE&G s operating cash flow increased $235 million from $678 million to $913 million for the year ended December 31, 2008, as compared to 2007, due primarily to

$199 million in higher collections of customer receivables,

a $164 million increase in deferred income taxes due to bonus depreciation and increased planned pension contributions,

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partially offset by decreases of $122 million in accounts payable due primarily to lower electric and gas payables, and

$39 million in increased pension fund contributions and related payments.

Energy Holdings

Energy Holdings operating cash flow decreased $373 million for the year ended December 31, 2009, as compared to 2008. The decrease was mainly attributable to tax payments related to the termination of leveraged lease investments in 2009, which were higher than tax payments made in 2008 related to asset sales. In addition, Energy Holdings made a $140 million tax deposit with the IRS in 2009 compared to a tax deposit of $80 million in 2008. Proceeds from the termination of leveraged leases in 2009 and the sale of investments in 2008 is reflected in our cash flows related to investing activities.

Energy Holdings operating cash flow decreased $441 million for the year ended December 31, 2008, as compared to 2007. The decrease was mainly attributable to increased tax payments in 2008.

Short-Term Liquidity

We have been managing our sources of liquidity in an effort to assure that we continue to have sufficient access to cash to operate our businesses in the event the capital markets do not allow for near-term financing at reasonable terms. We also monitor the financial condition and concentration of lenders in our bank facilities. There is no provision in any of our credit facilities that would require lenders in that facility to assume the loan commitments of any other financial institution that fails to meet its loan commitments. As of December 31, 2009, no single institution represented more than 11% of the commitments in our credit facilities.

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries liquidity needs. Our total credit facilities and available liquidity as of December 31, 2009 were as follows:

	As of December 31, 2009		
Company/Facility	**Total Facility**	**Usage(A)**	**Liquidity Available**
		Millions	
PSEG	$ 1,000	$ 523	$ 477
Power	2,050	159	1,891
PSE&G	600		600
Total	**$ 3,650**	**$ 682**	**$ 2,968**

(A) Usage does not include $26 million borrowed under PSEG s uncommitted bilateral agreement.

In July 2009, Power entered into a new $350 million syndicated credit facility that expires in July 2011. This new facility is available for funding the obligations of Power and its subsidiaries. Also in July 2009, Energy Holdings terminated its $136 million syndicated credit facility. As noted above, the PSEG credit facilities can be used to support subsidiary liquidity needs, including those of Energy Holdings.

In September 2009, a $50 million bilateral credit facility and a $150 million bilateral credit facility expired at Power. In March 2010, a $100 million of bilateral credit facility at Power is scheduled to expire. We review our liquidity requirements on a regular basis. As of December 31, 2009, our total credit facility capacity was in excess of our anticipated maximum liquidity requirements through 2010. For additional information, see Item 8. Financial Statements and Supplementary Data Note 12. Commitments and Contingent Liabilities and Note 13. Schedule of Consolidated Debt. Given current economic conditions, no assurances can be given that we will be able to replace expiring facilities on commercially reasonable terms.

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Long-Term Debt Financing

PSEG and Power have no debt maturities scheduled in 2010. PSE&G has $300 million of a debt maturity upcoming in 2010 excluding securitized debt. This maturity will occur during the first quarter of 2010. We believe that we will be able to refinance or retire this obligation given our current financial position and demonstrated continued access to the capital markets.

For a discussion of our long-term debt transactions during 2009 and into 2010, see Item 8. Financial Statements and Supplementary Data Note 13. Schedule of Consolidated Debt.

Debt Covenants

Our credit agreements may contain maximum debt to equity ratios, minimum cash flow tests 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 Refun