PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-K
February 28, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
100 F ST. N.E.
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

S **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2007,
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

000-49614

PSEG POWER LLC
(A Delaware Limited Liability Company)
80 Park Plaza T25
Newark, New Jersey 07102-4194
973 430-7000
http://www.pseg.com

22-3663480

001-00973

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(A New Jersey Corporation)
80 Park Plaza, P.O. Box 570
Newark, New Jersey 07101-0570
973 430-7000
http://www.pseg.com

22-1212800

Securities registered pursuant to Section 12(b) of the Act:

Registrant

Title of Each Class

Name of Each Exchange On Which Registered

Public Service Enterprise Group Incorporated

Common Stock without par value

New York Stock Exchange

Registrant

Title of Each Class

Title of Each Class

Name of Each Exchange
On Which Registered

Public Service Electric
and Gas Company

Cumulative Preferred Stock
$100 par value Series:

First and Refunding
Mortgage Bonds:

Series

Due

4.08%

91/4

%

CC

2021

4.18%

63/4

%

VV

2016

New York Stock Exchange

4.30%

63/8

%

YY

2023

5.05%

8

%

2037

5.28%

5

%

2037

(Cover continued on next page)

(Cover continued from previous page)

Securities registered pursuant to Section 12(g) of the Act:

Registrant

Title of Class

PSEG Power LLC

Limited Liability Company Membership Interest

Public Service Electric and Gas Company

6.92% Cumulative Preferred Stock $100 par value
Medium-Term Notes, Series A
Medium-Term Notes, Series B
Medium-Term Notes, Series C
Medium-Term Notes, Series D
Medium-Term Notes, Series E

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 S

No £

PSEG Power LLC

Yes £

No S

Public Service Electric and Gas Company

Yes £

No S

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 S

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 S 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. S

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Public Service Enterprise Group Incorporated

Large accelerated filer S

Accelerated filer £

Non-accelerated filer £

PSEG Power LLC

Large accelerated filer £

Accelerated filer £

Non-accelerated filer S

Public Service Electric and Gas Company

Large accelerated filer £

Accelerated filer £

Non-accelerated filer S

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 S

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2007 was $22,248,331,515 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated s sole class of Common Stock as of February 4, 2008 was 508,456,850, after giving effect for the two-for-one stock split.

PSEG Power LLC is a wholly owned subsidiary of Public Service Enterprise Group Incorporated and meets the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

As of February 4, 2008, 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.

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 2008 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 5, 2008, 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, 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 Operation, 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, policies and regulation, including market rules that may adversely affect our operating results.

Any inability of our energy transmission and distribution businesses to obtain adequate and timely rate relief and/or regulatory approvals from federal and/or state regulators.

Changes in federal and/or 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 that might adversely affect our ability to continue to operate that unit or other units at the same site.

Any inability to balance our energy obligations, available supply and trading risks.

Any deterioration in our credit quality.

Any inability to realize anticipated tax benefits or retain tax credits.

Increases in the cost of or interruption in the supply of fuel and other commodities necessary to the operation of our generating units.

Delays or cost escalations in our construction and development activities.

Adverse capital market performance of our decommissioning and defined benefit plan trust funds.

Changes in technology and/or 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. Except as may be required by the federal securities laws, we expressly disclaim any obligation or undertaking to release publicly any updates or revisions to these forward-looking statements to reflect events or circumstances that occur or arise or are anticipated to occur or arise after the date hereof. 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.

GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below:

APB

Accounting Principles Board

ARO

Asset Retirement Obligation

BEC

Bethlehem Energy Center

BGS

Basic Generation Service

BGSS

Basic Gas Supply Service

BPU

New Jersey Board of Public Utilities

CERCLA

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980

CIEP

Commercial and Industrial Energy Price

CO2

carbon dioxide

Competition Act

New Jersey Electric Discount and Energy Competition Act

DOE

U.S. Department of Energy

EDC

New Jersey Electric Distribution Company

EGDC

Enterprise Group Development Corporation

EITF

Emerging Issues Task Force

EMP

New Jersey Energy Master Plan

Energy Holdings

PSEG Energy Holdings L.L.C.

EPA

U.S. Environmental Protection Agency

ER&T

PSEG Energy Resources & Trade LLC

ERCOT

Electric Reliability Council of Texas

FASB

Financial Accounting Standards Board

FERC

Federal Energy Regulatory Commission

FIN

FASB Interpretation Number

Fossil

PSEG Fossil LLC

FSP

FASB Staff Position

FWPCA

Federal Water Pollution Control Act

GAAP

generally accepted accounting principles in the U.S.

Global

PSEG Global L.L.C.

GWhr

gigawatt hour

Hope Creek

Hope Creek Nuclear Generating Station

kWh

Kilowatt-hour

LTIP

Long-Term Incentive Plan

MBR

market-based rates

MD&A

Management s Discussion and Analysis of Financial Condition and Results of Operations

MGP

Manufactured Gas Plant

MICP

Management Incentive Compensation Plan

MOU

memorandum of understanding

MTC

Market Transition Charge

MTM

mark-to-market

MW

megawatts

NDT

Nuclear Decommissioning Trust

NEO

Named Executive Officer

NERC

North American Electric Reliability Corporation

NGC

Non-Utility Generation Clause

NJDEP

New Jersey Department of Environmental Protection

Notes

Notes to Consolidated Financial Statements

NRC

Nuclear Regulatory Commission

Nuclear

PSEG Nuclear LLC

NUG

Non-Utility Generation

NYISO

New York Independent System Operator

OPEB

Other Postretirement Benefits

Peach Bottom

Peach Bottom Atomic Power Station

PJM

PJM Interconnection, L.L.C.

Power

PSEG Power LLC

PPA

power purchase agreement

PSE&G

Public Service Electric and Gas Company

PSEG

Public Service Enterprise Group Incorporated

RAC

Remediation Adjustment Clause

Resources

PSEG Resources L.L.C.

RGGI

Regional Greenhouse Gas Initiative

RPS

BPU s Renewal Portfolio Standard

Salem

Salem Nuclear Generating Station

SBC

Societal Benefits Clause

Services

PSEG Services Corporation

SFAS

Statement of Financial Accounting Standard

Spill Act

New Jersey Spill Compensation and Control Act

TPS

third party supplier

Transition Funding

PSE&G Transition Funding LLC

Transition Funding II

PSE&G Transition Funding II LLC

FILING FORMAT

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 contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each makes representations only as to itself and its subsidiaries and makes no other representations whatsoever as to any other company.

WHERE TO FIND MORE INFORMATION

PSEG, Power and PSE&G file annual, quarterly and special reports, proxy statements and other information with the Securities and Exchange Commission (SEC). You may read and copy any document that PSEG, Power and PSE&G 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 PSEG s, Power s and PSE&G s filed documents from commercial document retrieval services, the SEC s internet website at www.sec.gov or PSEG s website at www.pseg.com. Information contained on PSEG s website should not be deemed incorporated into or as a part of this report. PSEG s Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about PSEG at the offices of the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

PSEG was incorporated under the laws of the State of New Jersey in 1985 and has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. PSEG has four principal direct wholly owned subsidiaries: Power, PSE&G, PSEG Energy Holdings L.L.C. (Energy Holdings) and PSEG Services Corporation (Services). The following organization chart shows PSEG and its principal subsidiaries, as well as the principal operating subsidiaries of Power: PSEG Fossil LLC (Fossil), PSEG Nuclear LLC (Nuclear) and PSEG Energy Resources & Trade LLC (ER&T); and of Energy Holdings: PSEG Global L.L.C. (Global) and PSEG Resources L.L.C. (Resources):

PSEG is an energy company with a diversified business mix. PSEG s operations are primarily in the Northeastern and Mid Atlantic United States (U.S.) and in other select markets. As the competitive portion of PSEG s business has grown, the resulting financial risks and rewards have become greater, causing financial requirements to change and increasing the volatility of earnings and cash flows.

For additional information, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) Overview of 2007 and Future Outlook.

Power

Power is a Delaware limited liability company, formed in 1999, and has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. Power is a multi-regional, wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management functions through three principal direct wholly owned subsidiaries: Nuclear, Fossil and ER&T.

As of December 31, 2007, Power s generation portfolio consisted of 13,314 MW of summer installed capacity, which is primarily located in the Northeast and Mid Atlantic regions of the U.S. in some of the nation s largest and most developed energy markets. For additional information, see Item 2. Properties.

As a merchant generator, Power s profit is derived from selling under contract or on the spot market a range of diverse products such as energy, capacity, emissions credits, congestion credits and a series of energy-related products used to optimize the operation of the energy grid. Power s revenues also include gas supply sales to PSE&G under the Basic Gas Supply Service (BGSS) contract with PSE&G (see Gas Supply below) and other customers.

Nuclear

Nuclear has ownership interests in five nuclear generating units: the Salem Nuclear Generating Station, Units 1 and 2 (Salem 1 and 2), each owned 57.41% by Nuclear and 42.59% by Exelon Generation LLC (Exelon Generation), each of which is operated by Nuclear; the Hope Creek Nuclear Generating Station (Hope Creek), which is owned 100% by Nuclear and operated by Nuclear; and the Peach Bottom Atomic Power Station Units 2 and 3 (Peach Bottom 2 and 3), each of which is operated by Exelon Generation and owned 50% by Nuclear and 50% by Exelon Generation. Salem 1 and 2 and Hope Creek are located at the same site. For additional information, see Item 2. Properties Power.

Nuclear Operations

From January 2005 through December 31, 2007, an Operating Services Contract (OSC) with Exelon Generation was in effect under which Exelon Generation provided key personnel to oversee daily plant operations at the Hope Creek and Salem nuclear generating stations and implemented a management model that Exelon Generation has used to manage its own nuclear facilities. In December 2006, Power announced its plans to resume direct management of the Salem and Hope Creek nuclear generating stations. As part of this plan, on January 1, 2007, the senior management team at Salem and Hope Creek, which consisted of three senior executives from Exelon, became employees of Power. Power continued to recruit additional employees to build its organizational structure and execute its plan in anticipation of direct management. As of January 1, 2008, the OSC was terminated and Power has resumed independent operation at Salem and Hope Creek.

During 2007, over half of Power s generating output was from its nuclear generating stations. Nuclear unit capacity factors for 2007 were as follows:

Unit	**Capacity Factor(A)**
Salem Unit 1	

89.0

%

Salem Unit 2

97.1

%

Hope Creek.

85.4

%

Peach Bottom Unit 2.

99.4

%

Peach Bottom Unit 3.

90.7

%

Total Power Ownership.

91.4

%

(A)

Maximum Dependable Capacity, net.

No assurances can be given that such capacity factors will be achieved in the future. For additional information on recent operational issues, see Regulatory Issues Nuclear Regulatory Commission (NRC).

Nuclear Fuel

Nuclear has several long-term purchase contracts for the supply of nuclear fuel for the Salem and Hope Creek Nuclear Generating Stations which include:

purchase of uranium (concentrates and uranium hexafluoride);

conversion of uranium concentrates to uranium hexafluoride;

enrichment of uranium hexafluoride; and

fabrication of nuclear fuel assemblies.

While the prices for uranium, conversion and enrichment are increasing, Nuclear does not anticipate any significant problems in meeting its future requirements; however, no assurances can be given.

Nuclear has been advised by Exelon Generation that it has similar purchase contracts to satisfy the fuel requirements for Peach Bottom. For additional information, see Item 7. MD&A Overview of 2007 and Future Outlook Power and Note 12. Commitments and Contingent Liabilities.

Fossil

Fossil has ownership interests in 17 generating stations in the Northeast and Mid Atlantic U.S. Fossil uses coal, natural gas and oil for electric generation. These fuels are purchased on behalf of Fossil by ER&T through various contracts and in the spot market and represent a significant portion of Power s working capital requirements. See Item 2. Properties for a list of these stations.

ER&T

ER&T purchases the capacity and energy produced by each of the generation subsidiaries of Power. In conjunction with these purchases, ER&T uses commodity and financial instruments designed to cover estimated commitments for Basic Generation Service (BGS) and other bilateral contract agreements. ER&T also markets electricity, capacity, ancillary services and natural gas products on a wholesale basis. ER&T is a fully integrated wholesale energy marketing and trading organization that is active in the long-term and spot wholesale energy and energy-related markets.

Electric Supply

Power s generation capacity is comprised of a diverse mix of fuels; 46% gas, 26% nuclear, 18% coal, 8% oil and 2% pumped storage. Power s fuel diversity serves to mitigate risks associated with fuel price volatility and market demand cycles.

The following table indicates proportionate gigawatt hour (GWhr) output of Power s generating stations by fuel type, based on actual 2007 output of approximately 53,200 GWhrs, and 2008 estimated output of approximately 54,000 GWhrs.

Generation by Fuel Type

Actual 2007

Estimated 2008(A)

Nuclear:

New Jersey facilities

36

%

37

%

Pennsylvania facilities

18

%

17

%

Fossil:

Coal:

New Jersey facilities

9

%

11

%

Pennsylvania facilities.

11

%

12

%

Connecticut facilities.

4

%

5

%

Oil and Natural Gas:

New Jersey facilities.

15

%

13

%

New York facilities

6

%

4

%

Connecticut facilities.

1

%

1

%

Total

100

%

100

%

(A)

No assurances can be given that actual 2008 output by source will match estimates.

For a discussion of Power s management and hedging strategy relating to its energy sales supply and fuel needs, see Market Price Environment and Item 7. MD&A Overview of 2007 and Future Outlook Power.

Coal Supply

Power purchases coal for certain of its fossil generation stations through various long-term commitments. In order to minimize emissions levels, Power s Bridgeport generating facility uses a specific type of coal obtained from Indonesia through a Fixed-Price (FP) supply contract that runs through 2011. Under a consent decree with the New Jersey Department of Environmental Protection (NJDEP) and the U.S. Environmental Protection Agency (EPA), the Hudson facility also utilizes this type of coal and has a FP supply contract that runs through 2010. If the supply of coal from Indonesia or equivalent coal from other sources was not available for these facilities, in the near term operations could be curtailed or suspended and in the long term, additional material capital expenditures could be required to modify the existing plants to enable their continued operation.

As of the end of 2007, one of Power s coal suppliers declared a force majeure, resulting in the interruption of coal shipments due to a mine fire. This supplier provides approximately 50% of the type of coal used at Power s 648 MW Mercer generation facility. In addition, approximately 35% of Mercer s coal supply is purchased through another contract in Venezuela, which was renegotiated in February 2008 and now provides for coal shipments through the end of 2008.

As described in Note 12. Commitments and Contingent Liabilities, Power is currently constructing pollution control equipment at its coal fired plants. When construction of those projects is complete, Power anticipates having more flexibility in the type of coal used at those facilities, thereby reducing its reliance on certain suppliers and reducing its risk of sourcing fuel for those facilities.

Power believes it has access to adequate fuel supplies, including transportation, for its facilities over the next several years; however, events such as those experienced at Mercer could result in higher than anticipated fuel costs as Power seeks alternate supply arrangements or purchases in the spot market. For additional information, see Item 7. MD&A Overview of 2007 and Future Outlook Power and Note 12. Commitments and Contingent Liabilities.

Gas Supply

Power sells gas to PSE&G under the BGSS contract. Power has a full requirements contract with PSE&G to meet the gas supply requirements of PSE&G s gas customers. The contract term runs through March 31, 2012, and year-to-year thereafter. Power charges PSE&G for gas commodity costs which PSE&G recovers from its customers.

Additionally, based upon availability, Power sells gas to others. Power s firm transportation, which is available every day of the year, can provide about 41% of PSE&G s peak daily gas requirements. The remainder comes from field storage, liquefied natural gas, seasonal purchases, contract peaking supply, propane and refinery and landfill gas. Power purchases gas for its gas operations directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipeline suppliers.

Power has approximately 1 billion cubic feet-per-day of firm transportation capacity under contract to meet the primary needs of PSE&G s gas consumers and the needs of its own generation fleet. Power supplements that supply with a total storage capacity of 78 billion cubic feet. This provides a maximum of approximately 1 billion cubic feet-per-day of gas during the winter season.

Power expects to be able to meet the energy-related demands of its firm natural gas customers and its own operations. However, the ability to maintain an adequate supply could be affected by several factors not within Power s control, including curtailments of natural gas by its suppliers, severe weather and the availability of feedstocks for the production of supplements to its natural gas supply.

Market Price Environment

System operators in the electric markets in which Power participates will generally dispatch the lowest variable cost units in the system first, with higher variable cost units dispatched as demand increases. As such, nuclear units, with their low variable cost of operation, will generally be dispatched whenever they are available. Coal units generally follow next in the merit order of dispatch and gas and oil units generally follow to meet the total amount of demand. With limited exceptions, the price that all dispatched units receive is set by the last, or marginal unit that is dispatched.

This method of determining supply and pricing creates an environment where 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. As such, significant changes in the price of natural gas will often translate into significant changes in the price of electricity.

Commodity prices, such as electricity, gas, coal and emissions, as well as the availability of Power s diverse fleet of generation units to produce these products, have a considerable effect on Power s profitability. There is significant volatility in commodity markets, including electricity, fuel and emission allowances. For example, the spot price of electricity at the quoted PJM Interconnection, L.L.C. (PJM) West market increased from an average of about $25 per megawatt hour (MWh) for 2002 to an average of about $60 per MWh in 2005 and in 2007 was about $55 per MWh. Similarly, the price of natural gas at the Henry Hub terminal increased from an average of about $3 per one million British Thermal Units (MMBtu) in 2002 to about $9 per MMBtu in 2005 and to about $7 per MMBtu on average in 2007. The prices at which transactions are entered into for future delivery of these products, as evidenced through the market for forward contracts at points such as PJM West are volatile as well. When averaged over a year, the historical annual spot prices and forward calendar prices as of year-end 2007 are reflected in the graphs below.

In the electricity markets where Power participates, the pricing of electricity varies by location. For example, prices may be higher in congested areas due to transmission constraints during peak demand periods, reflecting the bid prices of the higher cost units that are dispatched to meet demand. This typically occurs in the eastern portion of PJM, where many of Power s plants are located. At various times, depending upon its production and its obligations, these price differentials can serve to increase or decrease Power s profitability.

While the prices reflected in the tables above do not necessarily represent prices at which Power has contracted, 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. While they 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 Power will be able to contract its output at these forward prices.

One type of contract that is material to Power s hedging strategy is the BGS contract in New Jersey that is awarded for 3-year periods through an auction process managed by the New Jersey Board of Public Utilities (BPU). The BGS contract is a full requirements contract that includes energy and capacity, ancillary and other services. Pricing for the BGS contracts for recent and future periods by the purchasing utility is as follows:

Load Zone
2005 2008
2006 2009
2007 2010
2008 2011

($/MWh)

PSE&G

$

65.41

$

102.51

$

98.88

$

111.15

Jersey Central Power and Light

$

65.70

$

100.44

$

99.64

$

114.09

Atlantic City Electric

$

66.48

$

103.99

$

99.59

$

116.50

Rockland Electric Company

$

71.79

$

111.14

$

109.99

$

120.49

Power is also provided with payments from the various markets for the capability to provide electricity, known as capacity payments, which are reflective of the value to the grid of having the assurance of sufficient generating capacity to meet system reliability and energy requirements, and to encourage the future investment in adequate sources of new generation to meet system demand. While there is generally sufficient capacity in the markets in which Power operates, there are certain areas in these markets where there are constraints in the transmission system, causing concerns for reliability and a more acute need for capacity. Some generators, including Power, announced the retirement of certain older generating facilities in these constrained areas due to insufficient revenues to support their continued operation. In separate instances, both PJM and the New England Power Pool (NEPOOL), in order to enable their continued availability, responded with Reliability-Must-Run (RMR) contracts that provide Power with payments which are not necessarily reflective of the full value of those units contribution to reliability. Such payment structure by its nature acknowledges that these units provide a reliability service that is not compensated for in the existing markets.

The Federal Energy Regulatory Commission (FERC) issued certain orders in 2006 related to market design that have changed the nature of capacity payments in PJM and in NEPOOL. In PJM, a new capacity-pricing regime known as the Reliability Pricing Model (RPM) provides generators with differentiated capacity payments based within a Load Deliverability Area. Similarly, the Forward Capacity Market (FCM) settlement in NEPOOL provides for locational capacity payments. Both market designs are based in part on the premise that a more structured, forward-looking, transparent pricing mechanism gives prospective investors in new generating facilities more clarity on the value of capacity, sending a pricing signal to encourage expansion of capacity to meet future market demands. The FERC has approved the market changes in each of these markets. RPM started June 1, 2007 and the FCM transition period began December 1, 2006. The majority of Power s generating capacity has experienced increases in value from aspects of these market designs, resulting in considerable additional revenue. Power cannot determine the long-term impacts of these market design changes.

PJM sets the prices that will be received by generating assets located within the Eastern Mid Atlantic Area Council (MAAC) zone, the MAAC zone, the MAAC + APS zone and PJM, other than within the Eastern MAAC and MAAC

+ APS zones (Rest of Pool) through RPM base residual auctions. Most of Power s generating assets are in the Eastern MAAC and MAAC zones. The clearing prices resulting from the first four base residual auctions are listed in the following table.

Zones

Delivery Year

June 1, 2007 to May 31, 2008

June 1, 2008 to May 31, 2009

June 1, 2009 to May 31, 2010

June 1, 2010 to May 31, 2011

MW-day

kW-yr

MW-day

kW-yr

MW-day

kW-yr

MW-day

kW-yr

Eastern MAAC

$

197.67

$

72.15

$

148.80

$

54.31

$

191.32

$

69.83

$

$

MAAC

$

$

$

$

$

$

$

174.29

$

63.62

MAAC + APS

$

$

$

$

$

191.32

$

69.83

$

$

Rest of Pool

$

40.80

$

14.89

$

111.92

$

40.85

$

97.82

$

35.70

$

174.29

$

63.62

As a normal part of its contracting strategy, Power enters into contracts to sell capacity for future delivery. One such contract, as discussed above, is the BGS contract, which includes several energy- related components, one of which is capacity. A significant portion of Power s capacity is contracted as part of the three-year BGS-FP auctions in which Power had won 11 tranches in 2005, 20 tranches in 2006, 19 tranches in 2007 and 17 tranches in 2008. On average, each of these BGS-FP tranches requires approximately 120 MW of capacity on a daily basis. In addition, prior to the capacity auctions, Power hedged a portion of its generation capacity with forward capacity sales contracts at prices lower than auction prices above. As a result, Power expects to see an increasing amount of its capacity realizing RPM auction pricing as these existing contracts expire.

The capacity auctions also determine the price that must be paid by an entity serving load in the various auction delivery areas such as Power s obligation to serve BGS in New Jersey. These prices differ from physical capacity resources due to import and export capability to and from lower priced areas. Auction clearing prices for the purchase of capacity in the zones where Power s obligations are located are listed in the following table.

Zones

Delivery Year

June 1, 2007 to May 31, 2008

June 1, 2008 to May 31, 2009

June 1, 2009 to May 31, 2010

June 1, 2010 to May 31, 2011

MW-day

kW-yr

MW-day

kW-yr

MW-day

kW-yr

MW-day

kW-yr

Eastern MAAC

$

177.51

$

64.79

$

143.51

$

52.38

$

188.55

$

68.82

$

$

MAAC

$

$

$

$

$

$

$

174.29

$

63.62

The balance of Power s PJM capacity has obtained price certainty through May 31, 2011 as a result of the first four RPM auctions. Power has obtained price certainty for all of its capacity in New England through May 31, 2010 as a result of the FP nature of the transitional FCM auction.

On a prospective basis, many factors will affect the pricing for capacity in PJM, including but not limited to:

changes in demand;

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 created by PJM, including increasing the potential number of zones to as many as 24 zones in future years, which could 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 Power s collection of RMR payments in PJM and NEPOOL and the RPM and FCM proposals, see Regulatory Issues Federal Regulation.

Competitive Environment

Power s competitors include merchant generators with or without trading capabilities, including banks, funds and other financial entities, utilities that have generating capability, utility companies that have formed generation and/or trading businesses, aggregators and wholesale power marketers. These participants compete with Power and one another in buying and selling in wholesale power pools, entering into bilateral contracts and selling to aggregated retail customers.

Power s businesses are also under competitive pressure due to Demand Side Management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by end-use consumers which would result in reduction in Power s load requirements. 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.

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

Also, environmental issues such as restrictions on carbon dioxide (CO2) emissions and other pollution may have a competitive impact on Power to the extent it is more expensive for its plants to remain compliant, thus affecting its ability to be a lower cost provider compared to competitors without such restrictions.

Customers

As Exempt Wholesale Generators, Power s subsidiaries do not directly serve retail customers. Power uses its generation facilities for the production of electricity for sale at the wholesale level. Power s customers consist mainly of wholesale buyers, primarily within PJM, but also in New York and NEPOOL. Power is at times a direct or indirect supplier of New Jersey s Electric Distribution Companies (EDCs), including PSE&G, depending on the positions it takes in the New Jersey BGS auctions. These contracts are full requirements contracts, where Power is responsible to serve a percentage of the full supply needs of the customer class being served, including energy, capacity, congestion and ancillary services. In addition, Power has four-year contracts with two Pennsylvania utilities expiring in 2008.

As mentioned in Gas Supply, Power has a full requirements contract, BGSS, with PSE&G to meet the gas supply requirements of PSE&G s gas customers.

For the year ended December 31, 2007, approximately 50% of Power s revenue was comprised of billings to PSE&G for BGS and BGSS. See Note 21. Related-Party Transactions for additional information.

Employee Relations

As of December 31, 2007, Power had 2,538 employees, of whom 1,412 employees (710 employees at Fossil and 702 employees at Nuclear) are represented by three union groups under six-year collective bargaining agreements, which were ratified in February, July and August 2005, respectively. Power believes that it maintains satisfactory relationships with its employees.

PSE&G

PSE&G is a New Jersey corporation, incorporated in 1924, and has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. PSE&G is an operating public utility company engaged principally in the transmission and distribution of electric energy and gas in New Jersey. In addition, PSE&G owns PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which are bankruptcy-remote entities that respectively purchased, pursuant to New Jersey s Electric Discount and Energy Competition Act, as amended (Competition Act), the irrevocable property rights to receive certain non-bypassable transition charges per kilowatt-hour (kWh) of electricity delivered to PSE&G customers and issued transition bonds secured by such property in payment for such property.

PSE&G provides electric and gas service in areas of New Jersey in which approximately 5.5 million people, about 70% of the state s population, reside. PSE&G s electric and gas service area is a corridor of approximately 2,600 square miles running diagonally across New Jersey from Bergen County in the northeast to an area below the city of Camden in the southwest. The greater portion of this area is served with both electricity and gas, but some parts are served with electricity only and other parts with gas only. This heavily populated, commercialized and industrialized territory encompasses most of New Jersey s largest municipalities, including its six largest cities Newark, Jersey City, Paterson, Elizabeth, Trenton and Camden in addition to approximately 300 suburban and rural communities. This service territory contains a diversified mix of commerce and industry, including major facilities of many nationally prominent corporations. PSE&G s load requirements are split among residential, commercial and industrial customers, described below under customers. PSE&G believes that it has all the non-exclusive franchise rights (including consents) necessary for its electric and gas distribution operations in the territory it serves. PSE&G primarily earns margins through the transmission and distribution of electricity and the distribution of gas. PSE&G s revenues for these services are based upon tariffs approved by the BPU and the FERC. PSE&G also earns margins through non-tariff competitive services.

Energy Supply

PSE&G distributes electric energy and gas to end-use customers within its designated service territory. All electric and gas customers in New Jersey have the ability to choose an electric energy and/or gas supplier. Pursuant to the BPU requirements, PSE&G serves as the supplier of last resort for electric and gas customers within its service territory. PSE&G earns no margin on the commodity portion of its electric and gas sales.

As shown in the table below, PSE&G continues to provide the electric energy and gas supply for the majority of the customers in its service territory for the year ended December 31, 2007.

GWh

%

Million Therms

%

PSE&G

35,152

79

%

2,201

63

%

Third Party Suppliers

9,543

21

%

1,302

37

%

Total Delivered

44,695

100

%

3,503

100

%

New Jersey s EDCs, including PSE&G, provide two types of BGS, BGS-FP and BGS-Commercial and Industrial Energy Price (CIEP). BGS is the default electric supply service for customers who do not choose a third party supplier (TPS) for electric supply requirements. BGS-FP provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term. BGS-FP rates change annually on June 1, and are based on the average BGS price obtained at auctions in the current year and two prior years.

PSE&G is required to provide BGS for all customers who are not supplied by a TPS. All of New Jersey s EDCs jointly procure the supply to meet their 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 EDCs.

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 has a full requirements contract through 2012 with Power to meet the supply requirements of PSE&G s default service gas customers. Power charges PSE&G for gas commodity costs which PSE&G recovers from its customers. Any difference between rates charged by Power under the BGSS contract and rates charged to PSE&G s residential customers is deferred and collected or refunded through adjustments in future rates

Market Price Environment

There continues to be significant volatility in commodity prices, including fuel, emission allowances and electricity. Such volatility can have a considerable impact on PSE&G since a rising commodity price environment results in higher delivered electric and gas rates for end-use customers, and may result in decreased demand by end users of both electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs may be deferred under PSEG s regulated rate structure. For additional information see Item 7. MD&A.

Competitive Environment

The electric and gas transmission and distribution business has minimal risks from competitors. PSE&G s transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since PSE&G earns its return by providing transmission and distribution service, not by supplying the commodity. The demand for electric energy and gas by PSE&G s customers is affected by customer conservation, economic conditions, weather and other factors not within PSE&G s control.

Customers

As of December 31, 2007, PSE&G provided service to 2.1 million electric customers and 1.7 million gas customers. In addition to its transmission and distribution business, PSE&G also offers appliance services and repairs to customers throughout its service territory. The following details the distribution of electric and gas sales among customer classes:

Customer Type

% of Sales

Electric

Gas

Commercial

56

%

36

%

Residential.

31

%

60

%

Industrial

13

%

4

%

Total

100

%

100

%

Employee Relations

As of December 31, 2007, PSE&G had 6,069 employees. PSE&G has six-year collective bargaining agreements, which were ratified in 2005, with four unions representing 4,838 employees. PSE&G believes that it maintains satisfactory relationships with its employees.

Energy Holdings

Global

Global has investments in power producers that own and operate electric generation in Texas, California and Hawaii, with smaller investments in New Hampshire and Pennsylvania. Global s assets include consolidated projects and those accounted for under the equity method and cost method. As of December 31, 2007, Global s domestic generation portfolio consisted of 2,395 MW of owned capacity, as discussed below. For additional information see Item 2. Properties.

Texas

Global owns 100% of PSEG Texas, LP (PSEG Texas) (Formerly Texas Independent Energy) which owns and operates two gas-fired, combined cycle generation facilities with a total generating capacity of 2,000 MW, one in Guadalupe County in south central Texas (Guadalupe) and one in Odessa in western Texas (Odessa). Guadalupe and Odessa each have a generation capacity of 1,000 MW. Effective January 1, 2008, Global contracted with Fossil to assume management responsibilities for Odessa and Guadalupe. Approximately 40% to 50% of the expected output of PSEG Texas for 2008 has been sold via bilateral agreements and additional bilateral sales for peak and off-peak services are expected to be signed as the year progresses. Any remaining uncommitted output will be sold in the Texas spot market. Included in Odessa s 1,000 MW of generation capacity is a 350 MW daily capacity call option at Odessa that expires on December 31, 2010. For additional information, see Market Price Environment, below.

California

Global owns 50% of GWF Power System L.P. (GWF) and GWF Hanford, Inc.(Hanford). Global has PPAs for the five GWF San Francisco Bay Area plants net output with Pacific Gas and Electric Company (PG&E) ending in 2020 and 2021 and a PPA for Hanford for its net output with PG&E ending in 2011. GWF and Hanford primarily acquire the petroleum coke used to fuel the plants through contracts with prices negotiated between the parties either semi-annually or annually. Three of the five GWF plants have been modified to burn a wider variety of petroleum coke products to mitigate fuel supply and pricing risk.

GWF Energy LLC (GWF Energy), which is 60% owned by Global and 40% owned by a power fund managed by Harbert, owns and operates three peaker plants in California. The output of these plants is sold under a PPA with the California Department of Water Resources (DWR) ending in 2011 and 2012. The DWR has the right to schedule energy and/or reserve capacity from each unit of the three plants for a maximum of 2,000 hours each year. Energy and capacity not scheduled by the DWR is available for sale by GWF Energy. The DWR supplies the natural gas when the units are scheduled for dispatch by the DWR. GWF Energy obtains the natural gas used to fuel its plants for non-DWR sales from the spot market on a non-firm basis.

Hawaii

Global owns 50% of Kalaeloa, a base load generating station on Oahu, Hawaii. All of the electricity generated by the Kalaeloa power plant is sold to the Hawaiian Electric Company, Inc. (HECO) under a PPA expiring in May 2016. Under a steam purchase and sale agreement expiring in May 2016, the Kalaeloa power plant supplies steam to the adjacent Tesoro refinery. The primary fuel, low sulfur fuel oil, is provided from the adjacent Tesoro refinery under a long-term all requirements contract. The refinery is interconnected to the power plant by a pipeline and preconditions the fuel oil prior to delivery. Back-up fuel supply is provided by HECO.

New Hampshire

Global owns 40% of Bridgewater, a 16 MW biomass-fired power plant located in New Hampshire. Prior to August 2007, Bridgewater sold power to Public Service of New Hampshire under a long term PPA. Bridgewater has entered into a three year contract with a third party to supply electricity and renewable energy credits (RECs) on an a unit contingent basis. The RECs will be qualified according to the Connecticut Renewable Portfolio Standard. Bridgewater s fuel supply comes from a well-developed system of local sources.

Other

Global has reduced its international risk by opportunistically monetizing the majority of its international investments. On December 18, 2007, Global announced that it intends to sell its investment in the SAESA Group. The SAESA Group consists of four distribution companies, one transmission company and a generation facility located in Chile.

Global is also continuing to explore options for its remaining international investments in Italy, Venezuela and India. These businesses had a total book asset value of approximately $120 million as of December 31, 2007.

Market Price Environment

Global s projects in California, Hawaii and New Hampshire are fully contracted under long-term PPAs with the public utilities or power procurers in those areas. Therefore, Global does not have price risk with respect to the output of such assets, and generally, with respect to such assets, has limited risk with respect to fuel prices. Global s risks related to these projects are primarily operational in nature and have historically been minimal.

Global s generation business in Texas (PSEG Texas) is a merchant generation business with higher risks. PSEG Texas competes in the Texas wholesale energy market administered by ERCOT. Wholesale electricity prices in the ERCOT market generally move with the price of natural gas because marginal demand is generally supplied by natural gas-fueled generation plants. Natural gas prices have increased significantly in recent years, but historically the price has fluctuated due to the effects of weather, changes in industrial demand and supply availability, and other economic and market factors. ERCOT is a bilateral market in which generation plants run as their contractual commitments dictate with ERCOT further dispatching units up or down to maintain system stability via the balancing energy market and through the deployment of ancillary service capacity, which are bid price markets. In the balancing energy and ancillary service markets, ERCOT will generally dispatch the lowest bids first unless local transmission congestion requires units to be dispatched out of order. The price that all dispatched units receive is set by the last, or marginal bidder that is dispatched. PSEG Texas generation assets are combined cycle gas-fired generation units, and generally have lower variable costs than less efficient gas and oil-fired generation units. As a result, during on-peak periods, the price of power in ERCOT is frequently set by generation units with higher variable costs than PSEG Texas generation assets. Unlike the markets in which Power competes, ERCOT does not have a capacity market, and as a result, all generators are compensated solely through energy revenues and revenues for ancillary services, which are subject to substantial volatility as power prices fluctuate. While Global s business in Texas performed well during 2006 and 2007 as higher natural gas prices resulted in higher energy prices, there can be no assurances that such pricing in the market will continue at these levels.

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Competitive Environment

Although PSEG Texas generating stations operate very efficiently relative to other gas-fired generating plants, new additions of generation capacity could make PSEG Texas plants less economical in the future. A number of competitors have announced plans to build additional coal-fired and gas-fired generation capacity in ERCOT. 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 PSEG Texas competitiveness.

Over the past several years, substantial amounts of additional wind generation capacity has been constructed in ERCOT, particularly in western Texas, where PSEG Texas Odessa generation facility is located. At the end of 2007, ERCOT had approximately 4,000 MW of installed wind capacity. 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 base load power in western Texas, especially during off-peak seasons.

While numerous competitors have announced plans to build substantial amounts of new wind generation capacity, an issue impacting the likelihood of these projects being built is the constrained amount of transmission capacity between western Texas, where wind generation units are typically sited but where power demand is relatively low, and the rest of Texas. In an effort to address these transmission constraints, the Public Utilities Commission of Texas (PUCT) has designated five Competitive Renewable Energy Zones (CREZs) in western Texas and the Texas Panhandle. The PUCT has requested that ERCOT develop transmission construction options within these CREZs that would allow for much greater levels of delivery of wind power from western Texas to customers throughout the ERCOT grid. Although it is not clear if these efforts at transmission expansion will be successful or, if so, what the economic impact will be, it is possible that substantial additional amounts of wind generation will be built in ERCOT as a result of such potential transmission expansion, which could impact market prices and PSEG Texas competitiveness.

ERCOT s upcoming transitions to nodal pricing from zonal pricing, currently targeted for December 2008, may impact the competitiveness of PSEG Texas generating plants. A nodal electricity market, such as the PJM market, is a centrally organized, day-ahead and real-time market for wholesale power in which generators are compensated based on their location in the system (i.e. node). The implementation of the nodal market design is expected to deliver improved price signals, improved dispatch efficiencies and direct assignment of local congestion costs. PSEG is currently evaluating this change in market design and cannot predict the potential impact this change will have on its Texas generation facilities.

Customers

As discussed above, Global has ownership interests in electric generation facilities which sell energy, capacity and ancillary services to numerous customers through PPAs, as well as into the wholesale market.

Resources

Resources has investments in energy-related financial transactions and manages a diversified portfolio of assets, including leveraged leases, operating leases, leveraged buyout funds, limited partnerships and marketable securities. Established in 1985, Resources has a portfolio of 47 separate investments. PSEG does not anticipate that Resources will be making significant additional investments in the near term (See Leveraged Lease Investments below).

The major components of Resources investment portfolio as a percent of its total assets as of December 31, 2007 were:

As of December 31, 2007

Amount

% of
Resources
Total Assets

(Millions)

Leveraged Leases

Energy-Related

Foreign

$

1,490

50

%

Domestic

1,060

35

%

Real Estate Domestic.

188

6

%

Commuter Rail Cars Foreign.

88

3

%

Total Leveraged Leases

2,826

94

%

Owned Property (real estate and aircraft)

114

4

%

Limited Partnerships, Other Investments & Current and Other Assets

52

2

%

Total Resources Assets

$

2,992

100

%

As of December 31, 2007, no single investment represented more than 10% of Resources total assets.

Leveraged Lease Investments

Resources maintains a portfolio that is designed to provide a fixed rate of return. Income on leveraged leases is recognized by a method which produces a constant rate of return on the outstanding investment in the lease, net of the related deferred tax liability, in the years in which the net investment is positive. Any gains or losses incurred as a result of a lease termination are recorded as Operating Revenues as these events occur in the ordinary course of business of managing the investment portfolio.

In a leveraged lease, the lessor acquires an asset by investing equity representing 15% to 20% of the cost of the asset and incurring non-recourse lease debt for the balance. 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. The ability of Resources to realize these tax benefits is dependent on operating gains generated by its affiliates and allocated pursuant to PSEG s consolidated tax sharing agreement. The Internal Revenue Service (IRS) has recently disallowed certain tax deductions claimed by Resources for certain of these leases. See Note 12. Commitments and Contingent Liabilities for further discussion. 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 generally accepted accounting principles in the U.S. (GAAP), the lease investment is recorded on a net basis and income is recognized as a constant return on the net unrecovered investment.

Resources has evaluated the lease investments it has made against specific risk factors. The assumed residual value risk, if any, is analyzed and verified by third parties at the time an investment is made. Credit risk is assessed and, in some cases, mitigated or eliminated through various structuring techniques, such as defeasance mechanisms and letters of credit. As of December 31, 2007, the weighted average credit rating of the lessees in the portfolio was A /A3 by S&P and Moody s, respectively. Resources has not taken currency risk in its cross-border lease investments. Transactions have been structured with rental payments denominated and payable in U.S. dollars. Resources, as a passive lessor or investor, has not taken operating risk with respect to the assets it owns, so leveraged leases have been structured with the lessee having an absolute obligation to make rental payments whether or not the related assets operate. The assets subject to lease are an integral element in Resources overall security and collateral position. If the value of such assets were to be impaired, the rate of return on a particular transaction could be affected. The operating characteristics and the business environment in which the assets operate are, therefore, important and must be understood and periodically evaluated. For this reason, Resources will retain, as necessary, experts to conduct appraisals on the assets it owns and leases.

For additional information on leases, including credit, tax and accounting risk s related to certain lessees, see Item 1A Risk Factors, Item 7. MD&A Results of Operations Energy Holdings, Item 7A. Qualitative and Quantitative Disclosures About Market Risk Credit Risk Energy Holdings and Note 12. Commitments and Contingent Liabilities.

Employee Relations

As of December 31, 2007, Energy Holdings had 112 direct employees. In addition, Energy Holdings subsidiaries, other than the SAESA Group, had a total of 48 employees, 19 of which are represented by unions under collective bargaining agreements that expire in June 2009. Energy Holdings believes that it maintains satisfactory relationships with its employees.

Services

Services is a New Jersey corporation with its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102. Services provides management and administrative and general services to PSEG and its subsidiaries. These include accounting, treasury, financial risk management, law, tax, communications, planning, development, human resources, corporate secretarial, information technology, investor relations, stockholder services, real estate, insurance, library, records and information services, security and certain other services. Services charges PSEG and its subsidiaries for the cost of work performed and services provided pursuant to the terms and conditions of intercompany service agreements. As of December 31, 2007, Services had 1,138 employees, including 106 employees represented by two union groups under six-year collective bargaining agreements that were ratified in February 2005. Services believes that it maintains satisfactory relationships with its employees.

REGULATORY ISSUES

Federal Regulation

FERC

PSEG, Power and PSE&G

The FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act, respectively. By virtue of its regulation of (a) interstate transmission and (b) wholesale sales of electricity and gas, the FERC has extensive oversight over public utilities as defined by the FPA. For example, FERC approval is usually required when a public utility company seeks to: sell or acquire an asset that is regulated by the FERC (such as a transmission line or a generating station); issue a corporate guarantee or issue debt; charge a rate for a wholesale sale under a contract or tariff; or engage in certain mergers and internal corporate reorganizations. Several PSEG subsidiaries, including PSE&G, Fossil, Nuclear and ER&T, as well as certain subsidiaries of Fossil and certain domestic subsidiaries of Energy Holdings, are public utilities as defined by the FPA.

The FERC also regulates generating facilities known as Qualifying Facilities (QFs) under the Public Utility Regulatory Policy Act (PURPA). PSEG, through Global, owns several QF plants. QFs are subject to many, but not all, of the same FERC requirements as public utilities such as PSE&G, Fossil, Nuclear and ER&T.

To ensure that public utilities and QFs are complying with its rules and regulations with respect to interstate transmission and wholesale energy sales, the FERC may impose civil penalties of up to $1 million per day per violation. Penalties may be imposed on FERC-regulated companies for any violation of a FERC order, rule, regulation or FERC-approved Tariff. As such, all FERC-regulated companies, including PSEG subsidiaries which are either public utilities or QFs, are affected by FERC activity in the area of compliance and all developments in this area may be material to the business of these regulated companies.

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<u>Regulation of Wholesale Sales Generation/Market Issues</u>

Market Power

Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. Public utilities may sell power at cost-based rates or may apply to the FERC for authority to sell power at market-based rates (MBR). In order to obtain approval to sell power at MBR, the FERC must first make a determination that the requesting company lacks market power in the relevant markets. Once this determination is made, and MBR authority is granted, the public utility s individual sales made under the MBR authority are not reviewed or approved by the FERC but are reported to the FERC in quarterly reports.

PSE&G, ER&T and certain subsidiaries of Fossil and Energy Holdings have applied for and received MBR authority from the FERC. The FERC requires that holders of MBR tariffs file an update, on a triennial basis, demonstrating that they continue to lack market power. Retention of MBR authority is critical to the maintenance of Power s revenues.

In 2007, the FERC issued new MBR rules that changed the way in which the FERC analyzes whether a company possesses market power and that narrowed the relevant market(s) to be analyzed. For example, the FERC will no longer look at all of PJM to examine whether a public utility operating in PJM possesses market power but may instead look at sub-markets within PJM.

In January 2008, PSE&G and ER&T filed with the FERC their respective updated market power reports as required by the FERC s new MBR rules. In addition, in this filing, Fossil and Nuclear, which currently sell all of their power to ER&T under FERC-approved cost-based rates, have asked for the authority to sell power at MBR. PSE&G, ER&T, Fossil and Nuclear have asserted in their MBR filing that they either lack any generation market power or, if they do posess any market power, that market power is being effectively mitigated. PSE&G, ER&T, Fossil and Nuclear have further asserted that, to the extent that the FERC analyzes market power held in the small sub-market of Northern PSEG, PJM mitigation rules (including price capping for bids) eliminate the potential for the exercise of market power in this sub-market. This MBR filing is currently pending, and the outcome cannot be predicted.

PJM s wholesale markets depend upon PJM s Market Monitoring Unit (MMU) being viewed as a well-functioning and independent entity capable of effectively analyzing and addressing market power issues within PJM and stepping in to impose mitigation measures when required. In 2007, various state commissions and consumer groups filed a complaint at the FERC challenging the MMU s independence by alleging that PJM was interfering with the MMU s operations. The FERC placed this matter on a fast track and ordered settlement discussions between all interested parties, which resulted in a settlement that was filed with the FERC in December 2007. Under the settlement, the MMU will be a stand-alone company, engaged by contract (initial 6-year term) by PJM, with separate employees. This approach differs from the pre-existing internal MMU model. This settlement is currently pending before FERC.

Cost-Based RMR Agreements

The FERC has permitted public utility generation owners (such as Fossil and Power Connecticut) to enter into RMR Agreements. These agreements provide cost-based compensation to a generation owner when a unit proposed for retirement is asked to continue operating for reliability purposes. Fossil s Sewaren 1, 2, 3 and 4 and Hudson 1 generating stations are currently operating under an RMR Tariff in PJM. The current term of the RMR agreement for Sewaren is through September 2008 and for Hudson Unit 1 is through September 2010. For additional information, see Note 12. Commitments and Contingent Liabilities.

In the NEPOOL, many owners of generation facilities have also filed with the FERC for RMR treatment. Power Connecticut currently collects FERC-approved monthly payments for the Bridgeport Harbor Station, Unit 2 and the New Haven Harbor Station, respectively. Both RMR agreements are scheduled to end in June 2010.

Receipt of RMR treatment for both the Fossil units and the Power Connecticut units has enabled these units to continue to operate and has had a positive effect on revenues for Power. Various parties, however, have challenged in court the continuation of RMR payments in New England, and thus, there is risk that such payments may be terminated by court or FERC order prior to the end of the terms of the RMR contracts.

Organized Wholesale Energy Markets Notice of Proposed Rulemaking (NOPR)

On February 21, 2008, FERC issued a NOPR with respect to competition in the organized wholesale energy markets. This NOPR seeks to address issues with respect to demand response, long-term energy contracts, MMUs and the responsiveness of RTOs and ISOs to customers and other stakeholders. PSEG is unable to predict the outcome of the NOPR process.

The Cross Hudson Project

Power is currently contemplating whether or not to disconnect its existing Bergen 2 generation station from the PJM grid and connect the station to the NYISO transmission grid via a direct generator lead which will be constructed by a third party. On January 17, 2008, Power and the third party filed a request for a declaratory order at FERC seeking clarification from FERC on the status and use of the proposed generator lead. Power and the third party requested that FERC make a determination that it will not order the generator lead to be reconnected to the PJM system, that Power s use of the generator lead will not be displaced by another party and the negotiated economic terms for the use of the generator lead are appropriate under the Federal Power Act. A number of parties, including the BPU and the New Jersey Division of Ratepayer Advocate, have filed protests in the FERC declaratory order proceeding opposing the proposed disconnection of Bergen 2 from the PJM grid.

On December 20, 2007, Power submitted a bid to the New York Power Authority s (NYPA) to supply power directly to New York City. In the event Power is successful in its bid, Power would disconnect its existing Bergen 2 generation station from the PJM grid in summer 2011 and connect the station to the NYISO transmission grid via the direct generator lead to be constructed.

Power has been working with PJM to ensure that the disconnection of Bergen 2 would not adversely impact reliability of the PJM system. Based on discussions to date with PJM, it appears that reliability could be maintained through a combination of new generation, continued operation of generation that was scheduled to retire and the construction of transmission upgrades. In the event that reliability cannot be adequately addressed, Power will not proceed with the disconnection of Bergen 2 from the PJM system.

Capacity Market Issues

In early 2006, certain interested market participants in New England agreed to a settlement that establishes the design of the region s market for installed capacity and which will be implemented gradually over four years. Commencing in December 2006, all generators in New England began receiving fixed capacity payments that escalate gradually over the transition period. RMR contracts, such as Power s, continue to be effective until the implementation of the new market design in 2010. 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. 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 so that they are incented to locate in those areas where generation capacity is most needed. Both PJM s RPM and New England s FCM have been challenged in court. Capacity market rules in both PJM and in New England may change in the future.

FERC Transmission Regulation

PJM Transmission Rate Design

In 2007, the FERC addressed the issue of how transmission rates, paid by PJM transmission customers such as ER&T and ultimately paid by PSE&G s retail customers, should be designed in PJM. Under PJM s pre-existing rate design, transmission customers paid rates within the particular transmission zone in which they took service (zonal rate design). Many parties argued to the FERC, however, that rates should be paid on a postage stamp basis *i.e.* all customers within PJM pay the same transmission rate, regardless of the distance of the transaction. The FERC ultimately decided to apply both rate design methodologies. The cost of new high voltage (500 kV and above) transmission facilities in PJM will be socialized and paid for by all transmission customers. For all existing facilities, costs will be allocated using the pre-existing zonal rate design. For new lower voltage transmission facilities, costs will be allocated using the beneficiary pays approach, as discussed below. This FERC decision has recently been upheld on rehearing but has been challenged by American Electric Power Company and the Illinois Commerce Commission. PSEG believes that FERC s decision is beneficial to PSE&G s customers and to Power as representing a fair allocation of costs for transmission expansions in PJM.

Transmission Rates and Cost Allocation

In 2007, PJM and its members reached a settlement regarding how to allocate costs for new lower voltage (below 500 kilovolts (kV)) transmission expansion. Specifically, PJM will use a beneficiary pays methodology, identifying the beneficiaries of a particular expansion and allocating costs to those beneficiaries. Power and PSE&G supported this settlement as properly allocating costs for such facilities and ensuring that only the correct amounts of costs are allocated to ratepayers. The settlement is currently pending approval by the FERC.

PJM Economic Transmission Construction Rules

PJM has proposed significant changes to the rules establishing how economic transmission gets built within PJM. Economic transmission is transmission that is being built not to address a reliability problem, but instead to reduce economic congestion on the system, as congestion can result in higher electricity prices paid by consumers located within congested areas. PJM proposes to forecast congestion levels well into the future and to use these forecasts as the basis for determining the benefits of an economic transmission project. Moreover, PJM s proposal permits economic transmission that is rate-based (*i.e.* transmission that is funded by a company s ratepayers and for which the company itself is not at financial risk) to be constructed as a first resort, rather than permit market solutions (transmission, generation and/or demand response) to first come forward to address congestion issues as is currently permitted in the New York Independent System Operator (NYISO).

Power and PSE&G have actively participated in the FERC proceeding that is still considering the specifics of PJM s economic transmission proposal. In this proceeding, Power and PSE&G have recommended the implementation of a voting mechanism that will permit the identified beneficiaries of an economic transmission project to vote on the merits of a particular economic transmission project and to decide whether it gets built.

Transmission Expansion

In June 2007, PSE&G endorsed the construction of three new 500 kV transmission lines intended to significantly improve the reliability of the electrical grid serving New Jersey customers. Also in June 2007, PJM approved construction of one of the proposed lines (Susquehanna-Roseland line) and construction responsibility was ultimately assigned to PSE&G and Pennsylvania Power and Light (PPL) for their respective service territories. The estimated cost of PSE&G s portion of this construction project is between $600 million and $650 million, and the line currently has an expected in-service date of 2012. The two other lines which PSE&G has endorsed have not yet been submitted to PJM for approval.

At the end of 2007, PSE&G and PPL jointly filed with the FERC to obtain incentive rate treatment for the Susquehanna-Roseland line in the form of a 150 basis point adder to return on equity. In addition, PSE&G has filed with the FERC to classify as transmission (rather than distribution) certain separate 69 kV facilities that PSE&G will construct.

Construction of the Susquehanna-Roseland line and the other transmission projects that have been endorsed by PSE&G is contingent upon obtaining all necessary landowner, municipal and state permits and approvals.

DOE Congestion Study

In early 2007, the DOE issued a National Electric Transmission Congestion Study (Congestion Study), as directed by Congress. This Congestion Study identified two areas in the U.S. as critical congestion areas; one of the areas is the region between New York and Washington, D.C and encompassing all of New Jersey. The DOE has the ability to designate transmission corridors in these critical congestion areas, which then gives the FERC the ability to site transmission projects within these corridors should the relevant state(s) fail to act in a timely manner.

In October 2007, the DOE acted to designate transmission corridors within these critical congestion areas. One of the corridors designated, for a twelve year period, is the Mid-Atlantic Area National Corridor. This corridor designation covers most of the PJM territory. The DOE report is subject to rehearing and is being challenged in court; thus the final outcome of this proceeding cannot be predicted. Should the Mid-Atlantic Area corridor designation remain intact, entities seeking to build transmission within its geographic scope, which includes New Jersey, most of Pennsylvania and New York, will be able to use the FERC s back-stop eminent domain authority in the future, if necessary to site transmission.

<u>Compliance</u>

Reliability Standards

One of the FERC s major new tasks in the compliance area is to ensure compliance with reliability standards developed by the North American Electric Reliability Corporation (NERC) and approved by the FERC. Congress has required the FERC to put in place, through NERC, national and regional reliability standards to ensure the reliability of the U.S. electric transmission system and to prevent major system black-outs. The NERC has developed, and the FERC has approved, many reliability standards, compliance with which is mandatory by all those entities (including transmission owners, generation owners and generation operators) that have the ability to impact upon the reliability of the bulk of the electric transmission system. Since these standards are applicable to transmission owners and generation owners and operators, PSEG, PSE&G, Power and Energy Holdings (or their subsidiaries) are obligated to comply with the standards and to ensure continuing compliance. In 2008, PSE&G will be audited by ReliabilityFirst Corporation, a regional arm of NERC, for NERC Reliability Standards compliance. Also in 2008, Energy Holdings Texas generating plants will be audited for NERC Reliability Standards compliance by the Texas Regional Entity. The FERC has the ability to impose penalties of up to $1 million per day per violation for any violations of NERC Reliability Standards.

FERC Standards of Conduct

The FERC is currently re-examining its Standards of Conduct rules. These rules govern the relationship between a transmission provider (a public utility that owns, operates or controls transmission facilities) and its energy affiliates (affiliated public utilities that engage in wholesale sales of electricity or gas). The rules are intended to ensure that there is a level playing field in the competitive wholesale market by preventing a transmission provider from, among other things, providing non-public information about the transmission system that would benefit the energy affiliates at the expense of unaffiliated wholesale market participants. PSE&G is currently subject to the FERC s Standards of Conduct as a transmission provider and subsidiaries of Power and Energy Holdings are subject to the Standards of Conduct as energy affiliates. Thus, any changes by the FERC to the existing Standards of Conduct may impact the interactions between these companies.

NRC

PSEG and Power

Nuclear s 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. Power anticipates filing for extensions of operating licenses for the Salem and Hope

Creek facilities in 2009. The current operating licenses of Power s nuclear facilities expire in the years shown below:

Facility

Year

Salem 1

2016

Salem 2

2020

Hope Creek

2026

Peach Bottom 2

2033

Peach Bottom 3

2034

Power is expected to add approximately 125 MW of additional generating capacity at Hope Creek with Phase II of its turbine replacement expected to be completed along with the Extended Power Uprate in the second quarter of 2008 upon receipt of NRC approval.

Additional NRC Oversight

Power has been advised by the NRC that Salem Unit 1 will be subject to additional oversight. The additional NRC oversight is due to a negative change in the performance indicator related to the plant s diesel back-up power system. In December 2007, one of Salem 1 s emergency diesel generators failed to start during NRC testing. This test failure, combined with another instance earlier in the year in which another of the unit s diesel generators failed to start and a third failure in 2005 in which an emergency diesel generator failed to run led to the NRC s action to downgrade the indicator. The change will result in a corresponding increase in the NRC s inspection and assessment oversight at Salem Unit 1. This increased oversight will include a supplemental inspection to provide assurance that the problem has been adequately addressed. Although no assurances can be given, Power believes it has satisfactorily corrected the condition and expects to be returned to a normal oversight level by the end of the first quarter of 2008.

PSE&G

Investment Tax Credits (ITC)

As of June 1999, the IRS had issued several private letter rulings (PLRs) that concluded that the refunding of excess deferred tax and ITC balances to utility customers was permitted only over the related assets regulatory lives, which for PSE&G, were terminated upon New Jersey s electric industry deregulation. Based on this fact, in 1999, PSEG and PSE&G reversed the deferred tax and ITC liability relating to PSE&G s generation assets that were transferred to Power, and recorded a $235 million reduction of the extraordinary charge due to the restructuring of the utility industry in New Jersey. Subsequently, PSE&G was directed by the BPU to seek a PLR from the IRS to determine if the ITC included in the impairment write-down of generation assets could be credited to customers without violating the tax normalization rules of the Internal Revenue Code. PSE&G filed a PLR request with the IRS in 2002.

On May 11, 2006, the IRS issued a PLR to PSE&G, which concluded that none of the generation ITC could be passed to utility customers without violating the normalization rules. While the holding in the PLR is favorable for PSE&G,

an outstanding Treasury regulation project could overturn the holding in the PLR if the Treasury were to alter a position set out in certain proposed regulations issued on December 21, 2005. PSEG and PSE&G cannot predict the final outcome of this matter.

State Regulation

New Jersey

PSEG, Power and PSE&G

The BPU is the regulatory authority that oversees electric and natural gas distribution companies in New Jersey. PSE&G is subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service and the issuance and sale of securities. PSE&G s ownership of certain transmission facilities in Pennsylvania is subject to regulation by the Pennsylvania Public Utility Commission (PAPUC), which oversees retail electric and natural gas service in Pennsylvania. Power and PSE&G are also subject to rules and regulations of the NJDEP and the New Jersey Department of Transportation.

As discussed below, various Power subsidiaries and Energy Holdings subsidiaries are subject to some state regulation in other individual states where they operate facilities, including New York, Pennsylvania, Connecticut, Texas, California, Hawaii and New Hampshire.

Rates

Electric and Gas Base Rates

PSE&G must file electric and gas base rate cases with the BPU in order to change base rates. The BPU also has authority to seek to adjust rates downward if it believes the rates are no longer just and reasonable. A settlement agreement was approved in November 2006 authorizing the partial elimination of a rate credit established in the Electric Base Rate Case approved in July 2003. This settlement resulted in an increase in electric distribution revenues of $47 million at then current sales volumes. PSE&G also settled its pending gas base rate case at that same time, resulting in an increase in gas distribution revenues of $40 million annually at then current sales volumes. In addition, gas book depreciation expense was reduced by $26 million annually, and gas accumulated cost of removal amortization was reduced by $13 million annually for five years. The November 2006 settlements, for both electric and gas, provided that PSE&G not seek new base rates to be effective prior to November 15, 2009. PSE&G also must file a joint electric and gas petition for any future base rate increases.

Rate Adjustment Clauses

In addition to base rate determinations, PSE&G may recover certain costs from customers pursuant to mechanisms, known as clauses. These 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 programs 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. Two of PSE&G s primary clauses are detailed in the following table:

Rate Clause	2007 Revenue	(Over) Under Recovered Balance as of December 31, 2007

(Millions)

Energy Efficiency and Renewable Energy

$

183

$

(3

)

Remediation Adjustment Clause (RAC)

33

102

Universal Service Fund (USF)

137

33

Social Programs

29

19

Total Societal Benefits Clause (SBC)

382

151

Non-Utility Generation Clause (NGC)

54

9

Total Clauses

$

436

$

160

SBC The SBC is a mechanism designed to insure 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 RAC and the 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 contracts with non-utility generators approved by the BPU. The BPU transferred the remaining balance from the former Market Transition Charge (MTC) to the NGC in March 2007. The MTC was formerly part of the Electric SBC. The 2007 Revenue above includes the MTC collections through March.

Pending Rate Adjustments

PSE&G filed for revisions to the energy efficiency and renewable energy programs, the NGC and Social Program recoveries in May 2007. The current request, as updated, proposes annual revenues of $141 million, $112 million and $58 million, respectively. A decision is expected by July 2008.

On December 14, 2007, PSE&G submitted its RAC-15 filing to the BPU seeking recovery of $36 million of RAC program costs incurred during the period August 1, 2006 through July 31, 2007. The expenditures in each RAC period are recovered over seven years. If approved as requested, the annual RAC revenues will decrease to approximately $14 million annually.

Recent Rate Adjustments

The current USF rates were approved by the BPU in October 2007 at an annual level of $103 million.

Energy Supply

BGS

New Jersey s EDCs, including PSE&G, provide two types of BGS, BGS-FP and BGS-CIEP. BGS is the default electric supply service for customers who do not choose a TPS for electric supply requirements. BGS-FP provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term. BGS-FP rates change annually on June 1, and are based on the average BGS price obtained at auctions in the current year and two prior years. BGS-CIEP provides supply for larger customers at hourly PJM real-time market prices for a term of 12 months. BGS-FP and BGS-CIEP represent approximately 82% and 18%, respectively, of PSE&G s BGS-eligible load.

All of New Jersey s EDCs jointly procure the supply to meet their 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 EDCs. Certain conditions are required to participate in these auctions. Energy suppliers must agree to execute the BGS Master Service Agreement, provide required security within three days of BPU certification of auction results and satisfy certain creditworthiness requirements. PSE&G earns no margin on the provision of BGS.

Through the BGS auctions, PSE&G has contracted for its anticipated BGS-Fixed Price load, as follows:

Auction Year

2005

2006

2007

2008

36 Month Terms Ending

May 2008

May 2009

May 2010

May 2011

(a)

Load (MW)

2,840

2,882

2,758

2,840

$ per kWh

$0.06541

$0.10251

$0.09888

$0.1115

(a)

Prices set in the February 2008 BGS Auction are effective on June 1, 2008 when the agreements for the 36-month (May 2008) supply agreements expire.

For additional information, see Note 5. Regulatory Matters 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. Revenues are matched with costs using deferred accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition PSE&G has 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 2012 with Power to meet the supply requirements of PSE&G s default service gas customers. Power charges PSE&G for gas commodity costs which PSE&G recovers from its 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.

There were no changes to the BGSS rate in 2007. In June 2007, PSE&G requested an increase in annual BGSS revenues of $39 million, excluding Sales and Use Tax, to be effective October 1, 2007. However, as a result of lower forward gas prices after the filing, the parties to the proceeding agreed that the requested increase was not necessary. The current BGSS rate will remain in effect and is considered final. A Stipulation including final terms has been executed and BPU approval is expected shortly.

Energy Policy

New Jersey Energy Master Plan (EMP)

The Governor of New Jersey has directed the BPU, in partnership with other New Jersey agencies, to develop an EMP. State law in New Jersey 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. In the Governor s directive regarding the EMP, the Governor established three specific goals:

reduce the state s projected energy use by 20% by the year 2020;

supply 20% of the state s electricity needs with certain renewable energy sources by 2020; and

emphasize energy efficiency, conservation and renewable energy resources to meet future increases in New Jersey electric demand without increasing New Jersey s reliance on non-renewable resources.

In November 2006, PSE&G submitted a number of strategies designed to improve efficiencies in customer use and increase the level of renewable generation and has been actively involved in the broad- based constituent working groups created to develop these strategies. In September 2007, the BPU held a stakeholder meeting on energy efficiency issues, and PSE&G submitted comments advocating a strong role for gas and electric utilities in meeting the state s energy efficiency goals. We expect the state to release a draft EMP in the second quarter of 2008, and a final plan is expected to be completed later in 2008. Generally, implementation of new or revised energy policy put forth in the EMP will require further regulatory or legislative actions. PSE&G has stated its desire to be a partner to the state in achieving the above-stated goals of the EMP. During 2007, to this end, PSE&G has proposed several programs in filings with the BPU, described below. Each of these pilot programs addresses a different component of the EMP goals, but all are aimed at demonstrating PSE&G s capabilities as a partner to the State of New Jersey. PSEG, Power and PSE&G cannot predict the contents of the EMP and its impacts.

Solar Initiative

On April 19, 2007, PSE&G filed a plan with the BPU designed to spur investment in solar power in New Jersey and meet energy goals under the EMP. Under the plan, PSE&G would invest approximately $100 million over two years following BPU approval of the plan in a pilot program to help finance the installation of solar systems throughout its service area. PSE&G would loan money to customers in its electric service territory for the installation of solar photovoltaic systems on the customers premises. The borrowers would repay the loans over a period of either 10 years (for residential customer loans) or 15 years (for all other loans) by providing PSE&G with solar renewable energy certificates (SRECs). Borrowers would also have the option to repay the loans with cash. PSE&G s proposal is conditioned on it being allowed to earn a fair return on and of its investment, and recover its administrative costs to implement the program, through its regulated rates.

If approved by the BPU, the program could begin in early 2008 and support 30 MW of solar power in the following two years, fulfilling approximately 50% of the BPU s Renewal Portfolio Standard requirements in PSE&G s service area for energy years 2009 and 2010. On July 12, 2007, the BPU established a schedule for consideration of this proposal. PSE&G has held a series of stakeholder meetings to discuss program details with interested parties. Settlement discussions are ongoing, with a BPU decision expected in early 2008. No assurances can be given that PSE&G s initiatives will be approved.

Advanced Metering Infrastructure Technologies

On December 11, 2007, PSE&G filed a petition with the BPU requesting expedited approval to deploy and test Advanced Metering Infrastructure technologies, to enable customers to monitor energy use, conserve energy, reduce costs during peak periods and reduce CO2 emissions that contribute to global climate change. If approved, PSE&G will install 32,500 advanced meters in customers homes and businesses and begin transmitting customer data in the summer of 2008.

Carbon Abatement Program

On December 6, 2007, PSE&G filed a petition with the BPU seeking expedited approval of a carbon abatement pilot program designed to curb energy consumption, resulting in lower customer bills and a meaningful reduction in CO2 emissions. The proposal, if approved, would enable PSE&G to determine the best way to implement broader initiatives to reach the State s aggressive carbon reduction goals. If the program is approved, PSE&G will commit up to $5 million to fund the carbon abatement programs. For additional information on CO2 emissions, see Environmental Matters.

Governance

Public Utility Holding Company Act of 1935 (PUHCA) Repeal

In 2005, the BPU initiated a proceeding to consider whether additional ratepayer protections were necessary in light of Congress repeal of PUHCA that year. The proceeding considered the BPU s current authority to protect utility ratepayers from risks associated with a utility being part of a holding company structure. The BPU determined that additional protections were necessary and imposed a requirement that (i) each New Jersey public utility and its holding company ensure that the aggregate assets of all nonutility activities in the holding company system do not exceed 25% of the aggregate assets of the utility and utility-related assets in the holding company system without first obtaining BPU consent, and (ii) the utility and its parent holding company certify on an annual basis that this requirement is being satisfied. PSE&G and PSEG currently satisfy these requirements and expect to continue to satisfy them based on the companies current business plans. However, constant monitoring will be required to ensure that the regulation is satisfied and to meet the annual certification requirement.

The BPU is currently developing new regulations that would increase the BPU s access to books and records, impose restrictions on service agreements between utilities and their affiliated service companies and impose additional requirements on utility board of director composition, utility participation in money pools and additional reporting obligations. It is expected that new regulations will be proposed as part of a public rulemaking process during 2008. PSEG and PSE&G are not able to predict the outcome of such rulemaking process.

Compliance

The BPU has statutory authority to conduct periodic audits of PSE&G s operations and its compliance with applicable affiliate rules and competition standards. The BPU has retained consultants to conduct periodic combined management/competitive service audits of New Jersey utilities which PSE&G expects to occur later in 2008. While PSE&G believes that its operations are in compliance with the BPU s affiliate standards and competitive service rules, it cannot predict the outcome of this process.

Gas Purchasing Strategies Audit

In 2007, the BPU engaged a contractor to perform an analysis of the gas purchasing practices and hedging strategies of the four New Jersey gas distribution companies, including PSE&G. The primary focus was to examine and compare the financial and physical hedging policies and practices of each company and to provide recommendations for improvements to these policies and practices. Over the past few months, the audit has proceeded with discovery and the conducting of interviews. The goal of the consultants is to issue a report of major recommendations during the first quarter of 2008. PSE&G cannot predict the outcome of this process.

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. The draft report addressed the SBC, MTC and Non-Utility Generation (NUG) deferred balances and took no issue with respect to the reconciliation method PSE&G employed in calculating the overrecovery of its MTC and other charges during the Phase I and Phase II four-year transition period. The draft report did include the comments of BPU staff as to the reconciliation method. For additional information regarding PSE&G s Deferral Audit, see Note 12.

Commitments and Contingent Liabilities.

RAC Audit

On February 4, 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.

Texas

PSEG Texas is a merchant generation business that participates, through its subsidiaries, Odessa-Ector Power Partners, L.P. (Odessa) and Guadalupe Power Partners, LP (Guadalupe), in the Texas wholesale energy market administered by ERCOT. Under the regulation of the Public Utility Commission of Texas, ERCOT performs three main roles in managing the electric power grid and marketplace: ensuring that the grid can accommodate scheduled energy transfers, ensuring grid reliability, and overseeing retail transactions. While neither PSEG Texas, Odessa nor Guadalupe are public utilities subject to the jurisdiction of the FERC, they are subject to FERC jurisdiction for purposes of complying with NERC s Reliability Standards (see discussion in Federal Regulation Compliance Reliability Standards).

SEGMENT INFORMATION

Financial information with respect to the business segments of PSEG, Power and PSE&G is set forth in Note 18. Financial Information by Business Segment.

ENVIRONMENTAL MATTERS

PSEG, Power and PSE&G

PSEG s operations are subject to environmental regulation by federal, regional, state and local authorities. For both domestic and foreign operations, areas of regulation may include air quality, water quality, site remediation, land use, waste disposal, aesthetics, impact on global climate and other matters. These environmental laws and regulations impact the manner in which PSEG s operations currently are conducted as well as to impose costs on PSEG to address the environmental impacts of its historic operations that may have been in full compliance with the laws at the time those operations were conducted.

To the extent that environmental requirements are more stringent and compliance more costly in certain domestic states where PSEG operates compared to other states that are part of the same market, such rules may impact its ability to compete within that market. Due to evolving environmental regulations, it is difficult to project expected costs of compliance and its impact on competition. For additional information related to environmental matters, see Item 1A. Risk Factors and Item 3. Legal Proceedings.

Global Climate Change

Recent scientific studies have found that human activities are responsible for increases in global warming trends. Fossil fuel-fired electric generating stations have been identified in such studies as a major source of air emissions that contribute to global warming. PSEG continues to strive to reduce its carbon footprint by developing renewables, promoting conservation and increasing carbon-free nuclear power. A federal program that would impose uniform requirements on all sources of greenhouse gas emissions has not been implemented, thereby allowing for state and regional programs that may establish requirements that impose different costs in different markets in which PSEG competes.

Multiple states, primarily in the Northeastern U.S., are developing state-specific or regional legislative initiatives to stimulate CO2 emission reductions in the electric power industry. New York initiated the Regional Greenhouse Gas

Initiative (RGGI) in April 2003. In RGGI, ten Northeastern states, including New Jersey, have signed a memorandum of understanding (MOU) intended to cap and reduce CO2 emissions from the electric power sector in the RGGI region. A model rule contemplates the creation of a CO2 allowance allocation and/or auction whereby CO2 generators in the electric power industry would be expected to receive through allocation, or purchase through an auction, CO2 allowances in an amount corresponding to each facility s emissions. A final model rule was issued on August 15, 2006 that includes MOU commitments and makes recommendations for states to move forward.

In July 2007, New Jersey adopted the Global Warming Response Act (GWRA), which sets goals for the reduction of greenhouse gas emissions in New Jersey. The GWRA specifically calls for stabilizing greenhouse gas emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. These provisions codify an Executive Order that the Governor signed in February. 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.

In January 2008, additional legislation was enacted in New Jersey related to the reduction of greenhouse gas emissions. The legislation authorized the NJDEP to sell, exchange, retire, assign, allocate or auction allowances from greenhouse gas emission reductions and set forth the procedural requirements to be followed by the NJDEP if allowances are to be conveyed using an auction. Proceeds raised from the auction will be deposited in the Global Warming Solutions Fund and will be used to provide grants and other forms of assistance for the purpose of energy efficiency, renewable energy, new high efficiency generation, to stimulate or reward investment in the development of innovative CO_2 reduction or avoidance technologies and stewardship of New Jersey s forests and tidal marshes. The law also authorizes the participation of regulated public utilities in renewable energy, conservation and energy efficiency activities. The law specifically enables the BPU to allow an electric or gas public utility to offer programs for energy efficiency, conservation and Class I Renewables and to recover associated costs, as well as a return on and of investment, in rates. The law requires the BPU to issue an order within 120 days following enactment that allows public utilities to offer energy efficiency and conservation programs, to invest in Class I renewable energy resources, and to offer Class I renewable energy programs in their respective service territories on a regulated basis. This order will be reflected in rules and regulations to be adopted subsequently by the BPU.

The law further provides that the BPU shall adopt an emissions portfolio standard or other regulatory mechanism, to mitigate leakage by July 1, 2009, unless the state s Attorney General determines that this will unconstitutionally burden interstate commerce or would be preempted by federal law. This would benefit Power s generating facilities as it would reduce or eliminate the competitive advantage that facilities outside the RGGI region would otherwise have by operating without the added costs for reducing CO_2 emissions. Leakage occurs when CO_2 emissions or other air pollutants from power plants outside of the RGGI region increase as a result of reduced operation of plants within the RGGI region, thereby undermining the emissions cap and worsening air quality. Absent the implementation of any mitigation mechanisms, the operations of plants within the RGGI region would be reduced since the added costs to reduce CO_2 emissions would increase operating costs making the less expensive facilities outside the RGGI region more likely to be dispatched.

PSEG supported the legislation to reduce CO_2 emissions and intends to work with the New Jersey agencies and other stakeholders in developing the methods to achieve the greenhouse gas reduction goals. The new legislation also authorizes the BPU to require the disclosure on customer bills of the environmental characteristics of the delivered energy, to develop an interim renewable energy portfolio standard, a requirement for net metering, and electric and gas energy efficiency portfolio standards.

The outcome of global climate change initiatives cannot be determined at this time; however, adoption of stringent CO_2 emissions reduction requirements in the Northeast, including the potential allocation of allowances to PSEG s facilities and the prices of allowances available through auction, could materially impact the operation of Power s fossil fuel-fired electric generating units. 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 thereby the need to purchase the most allowances. Gas-fired units would require fewer CO_2 allowances and nuclear units would not need CO_2 allowances, consistent with their emissions profiles.

Air Pollution Control

The Federal Clean Air Act (CAA) and its implementing regulations require controls of emissions from sources of air pollution and also impose record keeping, reporting and permit requirements. Facilities in the U.S. that Power and Energy Holdings operate or in which they have an ownership interest are subject to these federal requirements, as well as requirements established under state and local air pollution laws applicable where those facilities are located.

Capital costs of complying with air pollution control requirements through 2010 are included in Power s estimate of construction expenditures in Item 7. MD&A Capital Requirements.

Sulfur Dioxide (SO2), Nitrogen Oxide (NOx) and Particulate Matter Emissions

To reduce emissions of SO2 for acid rain prevention, the CAA sets a cap on total SO2 emissions from affected units and allocates SO2 allowances (each allowance authorizes the emission of one ton of SO2) to those units. Generation units with emissions greater than their allocations can obtain allowances from sources that have excess allowances. At this time, Power does not expect to incur material expenditures to continue complying with the acid rain SO2 emissions program. The EPA has issued regulations (commonly known as the NOx State Implementation Plan Call) requiring 19 states in the eastern half of the U.S. and the District of Colombia to reduce and cap NOx emissions from power plant and industrial sources. The NOx reduction requirements are consistent with requirements already in place in New Jersey, New York, Connecticut and Pennsylvania, and therefore have not had an additional impact on the capacity available from Power s facilities in those states. Power has been implementing measures to reduce NOx emissions at several of its units in an effort to reduce the impact of any further increases to the costs of allowances.

In 1997, the EPA adopted a new air quality standard for fine particulate matter and a revised air quality standard for ozone. In 2004, the EPA identified and designated areas of the U.S. that fail to meet the revised federal health standard for ozone or the new federal health standard for fine particulates. States are expected to develop regulatory measures necessary to achieve and maintain the health standards, which may require reductions in NOx and SO2 emissions. Additional NOx and SO2 reductions also may be required to satisfy requirements of an EPA rule protecting visibility in many of the nation s Class 1 (pristine) environmental areas. Most of Power s fossil facilities would be affected by these initiatives.

In May 2005, the EPA published the final Clean Air Interstate Rule (CAIR) that identifies 28 states and the District of Columbia as contributing significantly to the levels of fine particulates and/or eight-hour ozone air quality in downwind states. New Jersey, New York, Pennsylvania, Texas and Connecticut are among the states the EPA lists in the CAIR. Based on state obligations to address interstate transport of pollutants under the CAA, the EPA has proposed a two-phased emission reduction program for NOx and SO2, with Phase 1 beginning in 2009 (NOx) and 2010 (SO2) and Phase 2 beginning 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.

Power is unable to determine whether any costs it may incur to comply with the above standards would be material.

In 2007 the Ozone Transport Commission (OTC) signed an MOU to reduce NOx emissions from High Electric Demand Day electric generation peaking units. The OTC is made up of 13 states in the Northeast and the District of Columbia and was created to address a continuing Ozone non-attainment challenge in the region. The states are in the process of developing regulations to meet emissions reductions identified in the MOU. Although the costs expected to be incurred as a result of these regulations will likely be material, compliance costs cannot be determined until the regulations are issued. Regulations are expected in the first half of 2008.

Other Air Pollutants

In March 2005, the EPA established a New Source Performance Standard limit for nickel emissions from oil-fired electric generating units, and a cap-and-trade program for mercury emissions from coal-fired electric generating units, with a first phase cap of 38 tons per year (tpy) in 2010 and a second phase cap of 15 tpy in 2018 (the Clean Air Mercury Rule). The United States Court of Appeals for the District of Columbia Circuit issued a decision on February 8, 2008 rejecting EPA s Clean Air Mercury Rule. As a result of this decision, the EPA is required to develop emissions standards for mercury and nickel emissions that do not rely on a cap-and-trade program. The full impact, if any, of this development is uncertain until the EPA issues the new emissions standards. Compliance with the new mercury standards, however, is not expected to have a material impact on Power s operations in New Jersey and Connecticut given the stringent mercury control requirements applicable in those states, as described below.

New Jersey and Connecticut have adopted standards for the reduction of emissions of mercury from coal-fired electric generating units. The regulations in New Jersey require the units to meet certain emissions limits or reduce emissions by 90% by December 15, 2007, unless a one-year extension is granted by NJDEP.

Under the New Jersey regulations, companies that are parties to multi-pollutant reduction agreements are permitted to postpone such reductions on half of their coal-fired electric generating capacity until December 15, 2012. With respect to Power s New Jersey facilities, half of the reductions that were required by December 15, 2007 are expected to be achieved through the installation of carbon injection technology at both Mercer Units, which was completed in January 2007. Because there is some uncertainty as to whether the system can consistently achieve the required reductions, Power has applied for, and received from NJDEP approval of a one-year extension through a facility-specific control plan that includes the installation of baghouses at the Mercer Units in 2008. Installation is scheduled to be completed by the end of 2008. At its Hudson plant, Power anticipates compliance consisting of the installation of a baghouse by the end of 2010.

The mercury control technologies are also part of Power s multi-pollutant reduction agreement, which resulted from the amended 2002 agreement that resolved issues arising out of the Prevention of Significant Deterioration (PSD) and the New Source Review (NSR) air pollution control programs.

Mercury emissions control standards effective in July 2008 in Connecticut require coal-fired power plants in Connecticut to achieve either an emissions limit or a 90% mercury removal efficiency through technology installed to control mercury emissions. Power anticipates compliance at its Bridgeport Harbor Station resulting from the installation of new technology prior to July 2008.

In February 2007, Pennsylvania finalized its state-specific requirements to reduce mercury emissions from coal-fired electric generating units. The Keystone and Conemaugh generating stations are positioned by 2010 to meet Phase I of the Pennsylvania mercury rule by benefiting from mercury reductions realized from the installation of controls for compliance with the CAIR. Phase 2 of the mercury rule will be addressed after a full evaluation of Phase 1 co-benefit reductions.

Some uncertainty exists regarding the feasibility of achieving the reductions in mercury emissions required by the New Jersey regulations and Connecticut statute; however, the estimated costs of technology believed to be capable of meeting these emissions limits at Power s coal-fired units in Connecticut, New Jersey and Pennsylvania have been incurred or are included in Power s capital expenditure forecast.

Mercer s mercury control technology was installed prior to December 15, 2007, but is currently operating under an NJDEP-approved Facility-Specific Mercury Control Plan that extends the deadline for compliance to December 15, 2008. The United States Court of Appeals for the District of Columbia Circuit issued a decision on February 8, 2008 rejecting the EPA s regulations that removed coal and oil-fired electric generating units from the list of facilities whose emissions of mercury and nickel would be regulated under the more stringent requirements for hazardous air pollutants and rejecting the EPA s regulations that allowed for an emissions trading program for mercury emissions. As a result of this decision, the EPA is required to develop emissions standards for mercury and nickel emissions. The full impact, if any, of this development is uncertain until the EPA issues the new emissions standards. Compliance with the new mercury standards, however, is not expected to have a material impact on Power s operations in New Jersey and Connecticut given the stringent mercury control requirements applicable in those states.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to waters of the U.S. 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 the NJDEP, to administer the NPDES program through state acts. Power and Energy Holdings also have ownership interests in domestic 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 Power s or Energy Holdings facilities in these jurisdictions.

The EPA promulgated regulations under FWPCA Section 316(b), which requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The Phase II rule covering large existing power plants became effective in 2004. The Phase II regulations provided five alternative methods by which a facility can demonstrate that it complies with the requirement for BTA for minimizing adverse environmental impacts associated with cooling water intake structures.

On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued its decision in litigation of the Phase II regulations brought by several environmental groups, the Attorneys General of six Northeastern states, including New Jersey, the Utility Water Act Group and several of its members, including Power. The court remanded major portions of the regulations and determined that Section 316(b) of the Clean Water Act does not support the use of restoration and the site-specific cost-benefit test. The court instructed the

EPA to reconsider the definition of BTA without comparing the costs of the best performing technology to its benefits. Prior to this decision, Power had used restoration and/or a site-specific cost-benefit test in applications it had filed to renew the permits at its once-through cooled plants, including Salem, Hudson and Mercer. Although the rule applies to all of Power s electric generating units that use surface waters for once-through cooling purposes, the impact of the rule and the decision of the court cannot be determined at this time for all of Power s facilities.

Nuclear, Fossil, another generating company and a trade association have filed petitions requesting that the US Supreme Court review the decision of the Second Circuit Court of Appeals. The Northeast states and the Solicitor General have received an extension to file their oppositions to those petitions, up through and including February 28, 2008. Industry petitioners, including Fossil and Nuclear, have until March 12, 2008 to file a reply brief. The briefs will then be distributed to the Supreme Court for consideration. If the Supreme Court accepts the case, then the matter would be set for oral argument most likely in the Court s 2008 2009 term, which begins in October. If the Court does not accept the case, then the Second Circuit s opinion stands and the regulations are remanded to the EPA for further consideration.

Depending on the outcome of any appeals, or actions by the EPA to repromulgate the regulations, this decision could have a material impact on Power s ability to renew its NPDES permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Sewaren, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to their existing intake structures and cooling systems. The costs of those upgrades to one or more of Power s once-through cooled plants could be material and would require economic review to determine whether to continue operations.

Hazardous Substance Liability

Because of the nature of Power s and PSE&G s respective businesses, including the production and delivery of electricity, the distribution of gas and, formerly, the manufacture of gas, various by- products and substances are or were produced or handled that contain constituents classified by federal and state authorities as hazardous. Federal and state laws impose liability for damages to the environment from hazardous substances. This liability can include obligations to conduct an 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 clean-ups of discharged hazardous substances. The clean-ups of hazardous substances can be more complicated and the costs higher when the hazardous substances are in a water body. For discussions of these hazardous substance issues and a discussion of potential liability for remedial action regarding the Passaic River, see Note 12. Commitments and Contingent Liabilities. For a discussion of remediation/clean-up actions involving Power and PSE&G, see Item 3. Legal Proceedings. For information regarding PSE&G s MGP Remediation Program, see Note 12. Commitments and Contingent Liabilities.

Natural Resource Damages (NRD)

CERCLA and the Spill Act authorize federal and state trustees for natural resources to assess 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. Power and PSE&G cannot assess the magnitude of the potential financial impact of this regulatory change.

On June 29, 2007, the State of New Jersey filed multiple lawsuits against parties, including PSE&G, who were alleged to be responsible for injuries to natural resources in New Jersey. Included in these lawsuits was a claim against PSE&G and others arising out of PSE&G s former Camden Coke facility, and a claim against PSE&G and others arising out of the Global Landfill matter. PSE&G has responded to the complaint in the NRD case arising out of the former Camden Coke site and is in the process of remediating that site under its MGP program. The time for PSE&G to answer the complaint in the NRD case arising out of the Global Landfill matter has been delayed until March 2008 to allow the parties to negotiate an order that would resolve the NRD claim. PSEG, PSE&G and Power cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to the Passaic River, Newark Bay or other natural resource damages claims; however, such costs could be material.

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

New Jersey Operating Permits

The New Jersey Air Pollution Control Act requires that certain sources of air emissions obtain operating permits issued by the NJDEP. All of Power s generating facilities in New Jersey are required to have such operating permits. The costs of compliance associated with any new requirements that may be imposed by these permits in the future are not known at this time and are not included in capital expenditures, but may be material.

Power

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, as amended (NWPA), 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 at a rate of one mil ($0.001) per kWh of nuclear generation, subject to such escalation as may be required to assure full cost recovery by the federal government. Under the NWPA, the DOE was required to begin taking possession of the spent nuclear fuel by no later than 1998. The DOE has announced that it does not expect a facility for such purpose to be available earlier than 2017.

Pursuant to NRC rules, 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 reactor operation (which may include the term of a revised or renewed license). Adequate spent fuel storage capacity is estimated to be available through 2011 for Salem 1 and 2015 for Salem 2. Power also has an on-site storage facility that is expected to satisfy the spent fuel storage needs of Hope Creek through the end of its current license in 2026. Exelon Generation has advised Power that it has a licensed and operational on-site storage facility at Peach Bottom that will satisfy Peach Bottom s spent fuel storage requirements until at least 2014.

Exelon Generation had previously advised Power that it had signed an agreement with the DOE, applicable to Peach Bottom, under which Exelon Generation would be reimbursed for costs incurred resulting from the DOE s delay in accepting spent nuclear fuel for permanent storage. Future costs incurred resulting from the DOE delays in accepting spent fuel will be reimbursed annually until the DOE fulfills its obligation to accept spent nuclear fuel. In addition, Exelon Generation and Nuclear are required to reimburse the DOE for the previously received credits from the Nuclear Waste Fund, plus lost earnings. Under this settlement, Power received $27 million for its share of previously incurred storage costs for Peach Bottom, $22 million of which was used for the required reimbursement to the Nuclear Waste Fund. Exelon Generation paid Power $5.4 million for its portion of the spent fuel storage costs reimbursed by the DOE in 2005 for costs incurred between October 1, 2003 and June 30, 2005.

In September 2001, Power filed a complaint in the U.S. Court of Federal Claims seeking damages for Salem and Hope Creek caused by the DOE not taking possession of spent nuclear fuel in 1998. On October 14, 2004, an order to show cause was issued regarding whether the U.S. Court of Federal Claims has jurisdiction over the matter. Power responded to this order in November 2004. On January 31, 2005, the Court dismissed the breach-of-contract claims of Power and three other utilities. Power moved for reconsideration in the U.S. Court of Federal Claims and jointly petitioned for permission to appeal the January 31, 2005 order to the U.S. Court of Appeals for the Federal Circuit. On September 29, 2006, the U.S. Court of Appeals for the Federal Circuit reversed the adverse U.S. Court of Federal Claims jurisdictional ruling and reinstated Power s claims in the U.S. Court of Federal Claims. No assurances can be given as to any damage recovery or the ultimate availability of a disposal facility.

In 2004, Delmarva Power & Light (DP&L) and Atlantic City Electric Company (ACE) commenced litigation against the DOE based on claims that they were injured by DOE s failure to timely commence removal of spent nuclear fuel as required at Salem and Hope Creek. Power believes that DP&L s and ACE s actions violate the terms of the purchase and sale agreements and invoked the binding arbitration provisions in the purchase and sale agreements to seek a determination that ACE and DP&L transferred to Power any and all of their potential claims with respect to DOE s failure to collect the spent nuclear fuel. The arbitration panel issued its decision in June 2007 in agreement with Power. ACE and DP&L requested that the U.S. Court of Appeal determine that the matter should not have been subject to arbitration, but the court instead dismissed ACE and DP&L s claims against DOE based on a finding that ACE and DP&L had transferred their claims to Power and DOE had accepted that transfer. In December 2007, the New Jersey Superior Court confirmed the award of the arbitration panel. ACE and DP&L have filed appeals of both decisions. These pending appeals could delay Power s ability to resolve its claims against DOE for failure to remove spent nuclear fuel from Salem and Hope Creek.

Spent Fuel Pool

The spent fuel pool at each Salem unit has an installed leakage collection system. This system was found to be obstructed at Salem Unit 1. Power developed a solution to maintain the design function of the leakage collection system at Salem Unit 1 and investigated the existence of any structural degradation that might have been caused by the obstruction. The concrete and reinforcing steel laboratory test results were completed in March 2006. Test results that have been collected as part of the ongoing testing indicate that no repairs are anticipated. The NRC issued Information Notice 2004 05 in March 2004 concerning this emerging industry issue and Power cannot predict what further actions the NRC may take on this matter.

Elevated concentrations of tritium in the shallow groundwater at Salem Unit 1 were detected in early 2003. This information was reported to the NJDEP and the NRC, as required. Power conducted a comprehensive investigation in accordance with NJDEP site remediation regulations to determine the source and extent of the tritium in the groundwater. Power is conducting remedial actions to address the contamination in accordance with a remedial action work plan approved by the NJDEP in November 2004. The remedial actions are expected to be ongoing for several years. The costs necessary to address this on-site groundwater contamination issue are not expected to be material.

Low Level Radioactive Waste (LLRW)

As a by-product of their operations, nuclear generation units produce LLRW. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. LLRW 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, including Power, continued access to the Barnwell LLRW disposal facility which is owned by South Carolina. Power believes that the Atlantic Compact will provide for adequate LLRW disposal for Salem and Hope Creek through the end of their current licenses, although no assurances can be given. Both Power and Exelon Generation have on-site LLRW storage facilities for Salem, Hope Creek and Peach Bottom, which have the capacity for at least five years of temporary storage for each facility. For information regarding Nuclear Spent Fuel Pool, see Note 12. Commitments and Contingent Liabilities.

ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our businesses. These factors could have an adverse impact on our financial position, results of operations or net cash flows and could cause results to differ materially from those expressed in any statements made by us, or on our behalf herein.

The factors discussed in Item 7. MD&A may also adversely 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 that may adversely affect our financial position, results of operations and cash flows.

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

We are subject to regulation by the FERC and the NRC, by federal, state and local authorities under environmental laws and by state public utility commissions under laws regulating our distribution business, among others.

Changes in regulation can cause significant delays in or materially affect business planning and transactions and can materially increase our costs. Regulation will affect almost every aspect of our businesses, 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 are recovered through adjustment clauses that are periodically reset to reflect current costs. Our transmission assets are regulated by the FERC and costs are recovered through rates set by the FERC. At the end of 2007, PSE&G and PPL jointly filed with the FERC to obtain incentive rate treatment for the PJM-approved Susquehanna-Roseland line, specifically a 150 basis point adder to return on equity. Inability to obtain a fair return on our investments or to recover material costs not included in rates would have an adverse effect on our business.

Obtain required regulatory approvals Power s subsidiary, ER&T, which markets all of Power s electric generation output, has been granted MBR authority from FERC, as have PSE&G, Power Connecticut and GWF Energy. FERC has recently issued new MBR rules which have significantly changed the way in which FERC analyzes whether a company possesses market power and have narrowed the relevant market(s) to be analyzed. With the narrowing of the markets, some of Power s generation assets could be considered to have market power due to their location in constrained areas within PJM. In January 2008, PSE&G and ER&T filed with the FERC their respective updated market power reports as required by the FERC s new MBR rules. PSE&G, ER&T, Fossil and Nuclear have asserted in their MBR filing that they either lack any generation market power or, if they do possess any market power, that market power is being effectively mitigated. PSE&G, ER&T, Fossil and Nuclear have further asserted that, to the extent that the FERC analyzes market power held in the small sub-market of Northern PSEG, PJM mitigation rules (including price capping for bids) eliminate the potential for the exercise of market power in this sub-market. This filing remains pending with FERC and the extent of any such mitigation measures, that may be required, cannot be determined at this time. Failure to maintain MBR eligibility, or the effects of any severe mitigation measures that may be required, could have a material adverse effect on PSEG, Power and PSE&G.

Our businesses 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, issue securities and pay dividends. Any failure to obtain any required regulatory approvals could materially adversely affect our results of operations and cash flows.

Comply with regulatory requirements Congress has required FERC to put in place, through the NERC, national and regional Standards to ensure the reliability of the United States electric transmission system and to prevent major system black-outs. Since these Standards are applicable to transmission owners and generation owners and operators, we are obligated to comply with the Standards and to ensure continuing compliance. In 2008, both PSE&G and Energy Holdings Texas generating plants will be audited for compliance with such Standards. FERC has the ability to impose penalties of up to $1 million per day per violation for any violations.

The BPU has also retained consultants to conduct periodic combined management/competitive service audits of New Jersey utilities which we expect to occur later in 2008. Such audits in the past have resulted in the imposition of significant additional requirements on PSEG and PSE&G. While we believe that we are in compliance with all affiliate standard requirements, we cannot predict the outcome of the audit.

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

Treatment of previously approved stranded costs We previously securitized $2.525 billion of PSE&G s generation and generation-related costs, which were determined by the BPU in 1999 to be stranded by industry restructuring, pursuant to an irrevocable, non-bypassable BPU financing order issued pursuant to the Competition Act. The Competition Act, and the authority of the BPU to issue its order, was upheld by the New Jersey Supreme court in 2001. In 2007, a new legal action, challenging the presumed constitutionality of certain provisions of the Competition Act, was filed in the Superior Court of New Jersey. This action sought injunctive relief from the continued collection of the transition bond charge (TBC) and related taxes by PSE&G, as well as recovery of amounts previously charged and collected. This action has been summarily dismissed by the Court. However, an appeal of this summary judgment is currently pending. Although the Court in dismissing the matter found no merit to the claims asserted, if such appeal ultimately was to be successful, ongoing recovery of funds to service our previous securitization could be affected. An administrative complaint by the same ratepayer was filed with the BPU. We have filed a motion to dismiss that complaint, which is pending.

Treatment of ITC included in previous write-down of generation assets The IRS has issued several PLRs that concluded that the refunding of excess deferred tax and ITC balances to utility customers was permitted only over the related assets regulatory lives, which for PSE&G, was terminated upon New Jersey s electric industry deregulation in 1999. Based on this fact, in 1999, we reversed the deferred tax and ITC liability relating to the generation assets that were transferred to Power, and recorded a $235 million reduction of the extraordinary charge due to such restructuring of the industry in New Jersey. Subsequently, PSE&G was directed by the BPU to seek a PLR from the IRS to determine if the ITC included in the impairment write-down of generation assets could be credited to customers without violating the tax normalization rules of the Internal Revenue Code. PSE&G filed a PLR request with the IRS in 2002. In May 2006, the IRS issued a PLR to PSE&G, which concluded that none of the generation ITC could be passed to utility customers without violating its normalization rules. While the holding in the PLR is favorable to the action we took, an outstanding Treasury regulation project could overturn that holding in the PLR if the Treasury were to alter a position set out in certain proposed regulations.

MTC collected during the four year industry transition period The BPU has raised certain questions with respect to the reconciliation method PSE&G had employed in calculating the overrecovery of its 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 2007, would be $127 million. While PSE&G believes the MTC methodology it used was fully litigated and resolved by the prior BPU Orders in its previous electric base rate case, deferral audit and deferral proceedings, PSE&G cannot predict the outcome of this proceeding.

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 and our subsidiaries conduct our operations and make capital expenditures. Further, such laws and regulations are subject to future changes that may result in increased compliance costs. We can give no assurance that we will be able to:

obtain all current or future required environmental approvals;

obtain any necessary modifications to existing environmental approvals;

maintain compliance with all applicable environmental laws, regulations and approvals; or

recover any resulting costs through future sales.

Delay in obtaining, or failure to obtain and maintain in full force and effect, any environmental permits or approvals, or delay or failure to satisfy any applicable environmental regulatory requirements, could prevent construction of new facilities, continued operation of existing facilities or sale of energy from these facilities or could result in us incurring significant additional costs which would materially affect our business, results of operations and cash flows.

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

Concerns over global climate change could result in laws and regulations to limit CO2 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 significantly impact our fossil generation facilities. Recent legislation enacted in New Jersey establishes aggressive goals for the reduction of CO2 emissions over a 40-year period. There could be material required expenditures, including the potential need to purchase CO2 emission allowances, and modifications to operations that may be needed to meet new regulatory requirements. Multiple states, primarily in the Northeastern U.S., are developing state-specific or regional legislative initiatives to stimulate CO2 emissions reductions in the electric power industry. The RGGI was initiated in April 2003 and is scheduled to begin in 2009. In RGGI, ten Northeastern states, including New Jersey, have signed a memorandum of understanding intended to cap and reduce CO2 emissions from the electric power sector in the RGGI region. Member states will control emissions of greenhouse gases by issuance of allowances to emit CO2 through an auction, allocation or a combination of the two methods.

A significant portion of our fossil fuel-fired electricity generators are located in states within the RGGI region and compete with electricity generators within PJM not located within a RGGI state. The costs or inability to purchase CO2 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.

Legislation recently enacted in New Jersey authorizes the NJDEP to sell, exchange, retire, assign, allocate or auction allowances from greenhouse gas emissions and sets forth the requirements to be followed by the NJDEP if allowances are to be conveyed using an auction. Proceeds raised from the auction will be deposited in the Global Warming Solutions Fund and will be used to provide grants and other forms of assistance for the purpose of energy efficiency, renewable energy, new high efficiency generation, to stimulate or reward investment in the development of innovative CO2 reduction or avoidance technologies and stewardship of New Jersey s forests and tidal marshes. The law further provides that the BPU shall adopt an emissions portfolio standard or other regulatory mechanism, to mitigate leakage by July 1, 2009 unless the state s Attorney General determines that this will unconstitutionally burden interstate commerce or would be preempted by federal law.

Potential closed-cycle cooling requirements Our Salem nuclear generating facility has a permit from the NJDEP allowing for the continued operation of the Salem facility with its existing cooling water system. That permit expired in July 2006. The NJDEP informed us that it strongly recommends that cooling water intake flow at the Salem facility be reduced commensurate with closed-cycle cooling. The application of FWPCA Section 316(b) could, as one option, require the installation of structures at the Salem facility to reduce cooling water intake commensurate with closed-cycle cooling, which would result in material costs of compliance. Our application to renew the permit, filed in February 2006 with the NJDEP, estimated the costs associated with cooling towers for Salem to be approximately $1 billion, of which Power s share would be 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 economic review to determine whether to continue operations.

Remediation of environmental contamination at current or formerly owned facilities We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former MGP operations subsidiaries are one source of such costs. Also, we are currently involved in a number of proceedings relating to sites where other hazardous substances 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.

On June 29, 2007, the State of New Jersey filed multiple lawsuits against parties, including PSE&G, who were alleged to be responsible for injuries to natural resources in New Jersey, including a site being remediated under PSE&G s 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.

More stringent environmental requirements in New Jersey Most of our generating facilities are located in the State of New Jersey. In particular, New Jersey s environmental programs are generally considered to be more stringent in comparison to similar programs in other states. Therefore, there may be instances where the facilities located in New Jersey are subject to more stringent 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 the state 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.

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

Over half of our total generation output each year is provided by our nuclear fleet, which comprises approximately 25% of our total owned generation capacity. For this reason, we are exposed to risks related to the successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. Significant risk factors relating to our nuclear generation include:

Storage and Disposal of Spent Nuclear Fuel We currently use on-site storage for spent nuclear fuel and incur costs to maintain this storage. Potential increased costs of storage, handling and 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 a 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 of the licenses for nuclear generating facilities. As with all of our facilities, as discussed above, our nuclear facilities are also subject to environmental regulation as rules continue to change.

Our New Jersey nuclear generating facilities are currently operating under NRC licenses that expire in 2016, 2020 and 2026. While we have applied for extensions to these licenses, the extension process takes approximately four to five years from the 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 both in the U.S. and elsewhere. The consequences of an accident can be severe and may include loss of life and property damage. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages. In addition, 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.

We may be adversely affected by changes in energy deregulation policies, including market design rules.

The energy industry continues to experience significant change. Various rules have recently been implemented to respond to commodity pricing, reliability and other industry concerns. Our business has been impacted by rules established that create locational capacity markets in each of PJM, New England and New York. 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. While the existence of these rules has had a positive impact on Power s revenues, as its generation in PJM and New England is located in constrained areas, both PJM s and New England s locational capacity market design rules are currently being

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challenged in court. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

We could also be impacted by a number of other events, including regulatory or legislative actions favoring non-competitive markets, energy efficiency initiatives, and regulatory policies favoring the construction of rate-based transmission that may result in increased imports of generation, which may be subject to less stringent environmental regulation, into areas served by Power s generation assets. Further, some of the market-based mechanisms in which Power participates, including Basic Generation Service (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 and the PJM market monitor. We can provide no assurance that these mechanisms will continue to exist in their current form for the foreseeable future.

We expect New Jersey to issue a draft EMP in the second quarter of 2008 and a final plan is expected to be completed later in 2008. The EMP may incorporate features that could have some of the effects described above.

On February 21, 2008, FERC issued a NOPR with respect to competition in the organized wholesale energy markets. This NOPR seeks to address issues with respect to demand response, long-term energy contracts, MMUs and the responsiveness of RTOs and ISOs to customers and other stakeholders. PSEG is unable to predict the outcome of the NOPR process.

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. This is especially important at our low-cost nuclear and coal 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 for certain types of coal used at several of our fossil stations;

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.

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

The revenues generated by the operation of the 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 other competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments through recovery of mandated rates payable by purchasers of electricity.

Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served.

Our 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 and pricing differentials at various geographic locations. These cannot be predicted with any 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 successfully develop or construct generation, transmission and distribution projects could adversely impact our businesses.

Our business plan calls for extensive investment by us 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 as well as other initiatives. Our success will depend, in part, on our ability to complete these projects within budgets, on commercially reasonable terms and conditions and, at PSE&G, 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. Currently, we have several significant projects underway or being contemplated, including:

the installation of pollution control equipment at our coal generating facilities;

the construction of the new Susquehanna-Roseland transmission line;

the construction or completion of potential growth initiatives;

the implementation of a new customer service system; and

the solar initiative proposed by PSE&G.

We face substantial competition in the merchant energy markets.

Our wholesale power and marketing businesses are subject to substantial competition from well-capitalized entities that may adversely affect our ability to make investments on favorable terms and achieve growth objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower returns. Some of the competitors include:

merchant generators, including coal;

banks, funds and other financial entities;

domestic and multi-national utility generators;

energy marketers;

fuel supply companies; and

affiliates of other industrial companies.

The regulatory, environmental, industry and operational issues discussed previously will have a significant impact on our ability to compete in energy markets. 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 usage by end-use consumers could result in a reduction in Power s 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 affect financial results.

If such issues were to occur, our market share could be eroded and the value of our power plants could be significantly impaired.

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 are:

Price fluctuations and collateral requirements We expect to meet our supply obligations through a combination of generation and energy purchases managed by ER&T. We also enter into derivative and other positions related to our generation assets and supply obligations. To the extent we hedge our costs, we will be subject to the risk of price fluctuations that could affect our future results. These include:

o

variability in costs, such as changes in the expected price of energy and capacity that we sell into the market;

o

increases in the price of energy purchased to meet supply obligations or the amount of excess energy sold into the market;

o

the cost of fuel to generate electricity; and

o

the cost of emission credits and congestion credits that we use to transmit electricity.

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 we were to lose our investment grade credit rating, we 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 we had lost our investment grade credit rating as of December 31, 2007, we would have been required to provide approximately $777 million in additional cash or cash-equivalent collateral.

Third party credit risk We sell generation output 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.

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

On November 16, 2006, the IRS issued its revenue agents audit report for tax years 1997 through 2000, which disallowed all deductions associated with certain of our leveraged lease transactions that are similar to a type that the IRS publicly announced its intention to challenge. In addition, the IRS imposed a 20% penalty for substantial understatement of tax liability. In February 2007, PSEG filed a protest to the Office of Appeals of the IRS. As of each of December 31, 2007 and December 31, 2006, Resources total gross investment in such transactions was $1.5 billion.

If the IRS disallowance of tax benefits associated with all of these lease transactions was sustained, $781 million of our deferred tax liabilities that have been recorded under leveraged lease accounting through December 31, 2007 would become currently payable. In addition, as of December 31, 2007 interest of approximately $179 million, after-tax, and penalties of $169 million may become payable, with potential additional interest and penalties of approximately $17 million accruing quarterly. We have assessed the probability of various outcomes to this matter and recorded the tax effect to be realized in accordance with FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 . In December 2007, PSEG deposited $100 million with the IRS to defray potential interest costs associated with this disputed tax liability. In the event PSEG is successful in its defense of its position, the deposit is fully refundable with interest.

While we believe that our tax position related to these transactions is proper based on applicable statutes, regulations and case law and we believe that it is more likely than not that we will prevail with respect to the IRS challenge, no assurances of such result can be given. If all deductions associated with these lease transactions, entered into by us between 1997 and 2002, are successfully challenged by the IRS, it would have a material adverse impact on our financial position, results of operations and cash flows.

If we are unable to access sufficient capital at reasonable rates or have sufficient liquidity in the amounts and at the times needed, our ability to successfully implement our financial strategies may be adversely affected.

Capital for projects and investments has been provided by internally-generated cash flow, equity issuances and borrowings. Continued access to debt capital from outside sources is required in order to efficiently fund the 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. As a result, no assurance can be given that we will be successful in obtaining financing for projects and investments or in funding the equity commitments required for such projects and investments in the future.

Capital market performance directly affects the asset values of our decommissioning 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 post-retirement benefit plans and to decommission nuclear generating plants. A significant decline in the market value of those assets, as was experienced from 2000 to 2002, may significantly increase our funding requirements for these obligations.

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, general public liability, boiler and machinery coverage, nuclear liability for nuclear generating units, replacement power and business interruptions, in amounts and with deductibles that management considers 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 to fund future payments on debt.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG

None.

Power and PSE&G

Not Applicable.

ITEM 2. PROPERTIES

PSEG does not own any property. All property is owned by PSEG subsidiaries. PSEG believes that it and its 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.

Generation Facilities

Power

As of December 31, 2007, Power s share of summer installed generating capacity was 13,314 MW, as shown in the following table:

OPERATING POWER PLANTS

Name

Location

Total Capacity

(MW)

%
Owned

Owned
Capacity
(MW)

Principal
Fuels
Used

Mission

Steam:

Hudson

NJ

913

100

%

913

Coal/Gas

Load Following

Mercer

NJ

648

100

%

648

Coal

Load Following

Sewaren

NJ

428

100

%

428

Gas

Load Following

Keystone(A)(B)

PA

1,687

23

%

388

Coal

Base Load

Conemaugh(A)(B)

PA

1,661

23

%

382

Coal

Base Load

Bridgeport Harbor

CT

503

100

%

503

Coal/Oil

Base Load/Load Following

New Haven Harbor

CT

448

100

%

448

Oil

Load Following

Total Steam

6,288

3,710

Nuclear:

Hope Creek.

NJ

1,061

100

%

1,061

Nuclear

Base Load

Salem 1 & 2(A).

NJ

2,304

57

%

1,323

Nuclear

Base Load

Peach Bottom 2 & 3(A)(C).

PA

2,224

50

%

1,112

Nuclear

Base Load

Total Nuclear

5,589

3,496

Combined Cycle:

Bergen

NJ

1,224

100

%

1,224

Gas

Load Following

Linden

NJ

1,186

100

%

1,186

Gas

Load Following

Bethlehem

NY

746

100

%

746

Gas

Load Following

Total Combined Cycle.

3,156

3,156

Combustion Turbine:

Essex

NJ

616

100

%

616

Gas

Peaking

Edison

NJ

504

100

%

504

Gas

Peaking

Kearny

NJ

441

100

%

441

Gas

Peaking

Burlington

NJ

557

100

%

557

Oil

Peaking

Linden

NJ

340

100

%

340

Gas

Peaking

Mercer

NJ

115

100

%

115

Gas

Peaking

Sewaren

NJ

105

100

%

105

Oil

Peaking

Bergen

NJ

21

100

%

21

Gas

Peaking

National Park

NJ

21

100

%

21

Gas

Peaking

Salem(A)

NJ

38

57

%

22

Oil

Peaking

Bridgeport Harbor

CT

10

100

%

10

Oil

Peaking

Total Combustion Turbine

2,768

2,752

Pumped Storage:

Yards Creek(A)(D)

NJ

400

50

%

200

Peaking

Total Operating Generation Plants

18,201

13,314

(A)

Power s share of jointly-owned facility.

(B)

Operated by Reliant Energy.

(C)

Operated by Exelon Generation.

(D)

Operated by JCP&L.

Global

Global has investments in the following generation facilities as of December 31, 2007:

OPERATING POWER PLANTS

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)

Principal
Fuels
Used

United States

PSEG Texas

Guadalupe

TX

1,000

100

%

1,000

Natural gas

Odessa

TX

1,000

100

%

1,000

Natural gas

Total PSEG Texas

2,000

2,000

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

60

%

57

Natural gas

Henrietta Peaker Plant

CA

97

60

%

58

Natural gas

Tracy Peaker Plant

CA

171

60

%

103

Natural gas

Total GWF Energy

363

218

Bridgewater

NH

16

40

%

6

Biomass

Conemaugh

PA

15

4

%

1

Hydro

Total United States

2,734

2,395

International(A)

PPN Power Generating Company Limited (PPN)

India

330

20

%

66

Naphtha/Natural gas

Bioenergie

Crotone

Italy

20

43

%

9

Biomass

Bando D   Argenta I

Italy

20

85

%

17

Biomass

Strongoli

Italy

40

43

%

17

Biomass

Total Bioenergie

80

43

Turboven

Maracay

Venezuela

60

50

%

30

Natural gas

Cagua

Venezuela

60

50

%

30

Natural gas

Total Turboven

120

60

Turbogeneradores de Maracay (TGM)

Venezuela

40

9

%

4

Natural gas

Natural gas/

SAESA Group

Chile

118

100

%

118

Gas/Oil/Hydro/Wind

Total International

688

291

Total Operating Power Plants

3,422

2,686

(A)

In December 2007, Global announced its intention to sell the SAESA Group of companies. Global is also continuing to explore options for its equity investments in its other international generation projects, PPN, Bioenergie, Turboven and TGM.

Transmission and Distribution Facilities

PSE&G

As of December 31, 2007, PSE&G s electric transmission and distribution system included 21,764 circuit miles, of which 7,729 circuit miles were underground, and 804,936 poles, of which 538,811 poles were jointly-owned. Approximately 99% of this property is located in New Jersey.

In addition, as of December 31, 2007, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2007, the daily gas capacity of PSE&G s 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,973,000 therms (approximately 2,886,000 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

As of December 31, 2007, PSE&G owned and operated 17,618 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 or regulating stations, all located in New Jersey, of which 28 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. These easements and other rights are deemed by PSE&G to be adequate for the purposes for which they are being used.

Office Buildings and Other Facilities

Power

Power rents office space from Services as its headquarters in Newark, New Jersey. Other leased properties include office, warehouse, classroom and storage space, primarily located in New Jersey. Power also owns the Central Maintenance Shop at Sewaren, New Jersey.

Power has a 57.41% ownership interest in approximately 13,000 acres in the Delaware River Estuary region to satisfy the condition of the New Jersey Pollutant Discharge Elimination System (NJPDES) permit issued for Salem. Power also owns several other facilities, including the on-site Nuclear Administration and Processing Center buildings.

Power has a 13.91% ownership interest in the 650-acre Merrill Creek Reservoir in Warren County, New Jersey and approximately 2,158 acres of land surrounding the reservoir. The reservoir was constructed to store water for release to the Delaware River during periods of low flow. Merrill Creek is jointly-owned by seven companies that have generation facilities along the Delaware River or its tributaries and use the river water in their operations.

Power believes that it maintains adequate insurance coverage against loss or damage to its 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 Note 12. Commitments and Contingent Liabilities.

PSE&G

PSE&G rents office space from Services as its headquarters in Newark, New Jersey. PSE&G also leases office space at various locations throughout New Jersey for district offices and offices for various corporate groups and services. PSE&G also owns various other sites for training, testing, parking, records storage, research, repair and maintenance, warehouse facilities and for other purposes related to its business.

In addition to the facilities discussed above, as of December 31, 2007, PSE&G owned 42 switching stations in New Jersey with an aggregate installed capacity of 22,809 megavolt-amperes and 245 substations with an aggregate installed capacity of 7,835 megavolt-amperes. In addition, four substations in New Jersey having an aggregate installed capacity of 109 megavolt-amperes were operated on leased property.

Services

Services leases a 25-story office tower for PSEG s corporate headquarters at 80 Park Plaza, Newark, New Jersey, together with an adjoining three-story building. In addition, Services owns the Maplewood Test Services Facility in Maplewood, New Jersey.

ITEM 3. LEGAL PROCEEDINGS

PSE&G

Competition Act

On April 23, 2007, PSE&G and Transition Funding were served with a copy of a purported class action complaint (Complaint) 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 TBC of PSE&G 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. On July 9, 2007, 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. PSE&G and Transition Funding filed a motion to dismiss the amended Complaint (or in the alternative for summary judgment) on July 30, 2007 and PSE&G filed on September 30, 2007 a motion with the BPU to dismiss the petition. On October 10, 2007, PSE&G and Transition Funding s motion to dismiss the amended Complaint was granted. The plaintiff has appealed this dismissal. PSE&G s motion to dismiss the BPU petition is pending (BPU Docket No. ER07070516).

Con Edison

In November 2001, Consolidated Edison Company of New York, Inc. (Con Edison) filed a complaint with the FERC against PSE&G, PJM and NYISO with the FERC asserting a failure to comply with agreements between PSE&G and Con Edison covering 1,000 MW of transmission. PSE&G denied the allegations set forth in the complaint. The FERC subsequently held hearings and issued a number of orders between 2002 and late 2007. Those decisions were largely favorable to PSE&G and generally held that PSE&G and the other respondents had complied with their obligations under the contracts. The FERC s orders, however, did require greater specificity in defining the parties respective obligations and, in conformance with FERC s requirements, the parties have met on numerous occasions for the purpose of developing detailed operational protocols.

On May 18, 2005, FERC accepted operational protocols jointly submitted by all parties that addressed FERC s basic findings. In subsequent filings to the FERC regarding the efficacy of these protocols, however, Con Edison continued to claim that the obligations under the agreements as interpreted by the FERC s orders are not being met. In December 30, 2005 and January 19, 2007 filings with the FERC, Con Edison claimed to have incurred $111 million in damages, and requested the FERC to require refunds of this amount. This claim was subsequently rejected by FERC on procedural grounds.

PJM, NYISO, Con Edison and PSE&G continue to meet under a work plan intended to address the remaining operational issues associated with the protocols and to address Con Edison s refund claim. As part of these discussions and in separate discussions, PSE&G and Con Edison have discussed the possibility of a comprehensive settlement of all matters raised in the November 2001 complaint. At the present time, however, these comprehensive settlement discussions have reached an impasse. Both PSE&G and Con Edison have sought judicial review of the FERC orders addressing these contracts before the D.C. Circuit Court of Appeals. As this matter is currently pending before the appeals court, PSEG and PSE&G are unable to predict the outcome of this proceeding.

PSEG, Power and PSE&G

In addition to the matters discussed above, see information on the following proceedings at the pages indicated for PSEG, Power and PSE&G as noted:

(1)

Page 15. (Power) PSEG Power Connecticut s filing with FERC on November 17, 2004, Docket No. ER05-231-000, to request RMR compensation.

(2)

Page 15. (PSEG and Power) FERC proceeding for issuance of a declaratory order relating to the proposed Cross Hudson project, Docket No. EL08-35-000.

(3)

Page 16. (PSEG, Power and PSE&G) PJM Reliability Pricing Model filed with FERC on August 31, 2005, Docket Nos. ERO5-1410-000 and EL05-148-000.

(4)

Page 16. (PSEG, Power and PSE&G) FERC proceeding relating to PJM Long-Term Transmission Rate Design, Docket No. EL05-121-000.

(5)

Page 20. (PSE&G) SBC/NGC Rate filing with the BPU on May 7, 2007, Docket Nos. ER07050303 & GR07050304.

(6)

Page 20. (PSE&G) Remediation Adjustment Clause filing with the BPU on April 25, 2005, Docket No. GR05040383.

(7)

Page 20. (Power and PSEG) Universal Service Fund mandated by the BPU under the Competition Act to recover costs under the Permanent Universal Service Fund and the Lifeline program.

(8)

Page 21. (PSE&G) PSE&G s BGSS Commodity filing with the BPU on May 28, 2004, Docket No. GR04050390.

(9)

Page 23. (PSEG, Power and PSE&G) BPU proceedings relating to ratepayer protections due to repeal of PUHCA under the Energy Policy Act of 2005, Docket No. AX05070641.

(10)

Pages 23 and 142. (PSE&G) Deferral Proceeding filed with the BPU on August 28, 2002, Docket No. EX02060363, and Deferral Audit beginning on October 2, 2002 at the BPU, Docket No. EA02060366.

(11)

Pages 27 and 138. (Power) Power s Petition for Review filed in the United States Court of Appeals for the District of Columbia Circuit on July 30, 2004 challenging the final rule of the EPA entitled National Pollutant Discharge Elimination System Final Regulations to Establish Requirements for Cooling Water Intake Structures at Phase II Existing Facilities, now transferred to and venued in the United States Court of Appeals for the Second Circuit with Docket No. 04-6696-ag.

(12)

Page 29. (Power) Filing of Complaint by Nuclear against the DOE on September 26, 2001 in the U.S. Court of Federal Claims, Docket No. 01-0551C seeking damages caused by DOE s failure to take possession of spent nuclear fuel. The complaint was amended to include PSE&G as a prior owner in interest.

(13)

Page 135. (PSE&G) Investigation Directive of NJDEP dated September 19, 2003 and additional investigation Notice dated September 15, 2003 by the EPA regarding the Passaic River site, Docket No. EX93060255.

(14)

Page 136. (Power and PSE&G) New Jersey Department of Environmental Protection v. BFI Waste Systems of New Jersey, Inc. et al., filed with New Jersey Superior Court on June 29, 2007.

(15)

Page 136. (Power and PSE&G) New Jersey Department of Environmental Protection v. Public Service Electric and Gas Co., et al., filed with New Jersey Superior Court on June 29, 2007, Docket No. L-3337-07.

(16)

Page 136. (Power) PSE&G s MGP Remediation Program instituted by NJDEP s Coal Gasification Facility Sites letter dated March 25, 1988.

(17)

Page 142. (PSE&G) BPU Order dated December 23, 2003, Docket No. EO02120955 relating to the New Jersey Interim Clean Energy Program.

Power and PSE&G

In addition, see the following environmental related matters involving governmental authorities. Power and PSE&G 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 their respective 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. 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) The EPA sent PSE&G, Power 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. Power and PSE&G are unable to predict the outcome of this matter; however, the related costs of this study are not expected to be material.

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

PSEG None.

Power None.

PSE&G None.

PART II

ITEM 5.

MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

PSEG

PSEG s Common Stock is listed on the New York Stock Exchange, Inc. As of December 31, 2007, there were 88,887 holders of record.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2002 in PSEG 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.

2002

2003

2004

2005

2006

2007

PSEG

$

100.00

$

143.78

$

178.42

$

232.27

$

245.83

$

373.49

S&P 500

$

100.00

$

128.63

$

142.58

$

149.57

$

173.14

$

182.63

DJ Utilities

$

100.00

$

129.08

$

167.87

$

209.77

$

244.67

$

293.76

S&P Electrics

$

100.00

$

123.84

$

156.54

$

183.98

$

226.58

$

278.87

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

Common Stock

High

Low

Dividend
Per Share

2007:

First Quarter

$

42.12

$

32.16

$

0.2925

Second Quarter

$

46.90

$

41.02

$

0.2925

Third Quarter

$

46.66

$

38.66

$

0.2925

Fourth Quarter

$

49.88

$

43.48

$

0.2925

2006:

First Quarter

$

36.23

$

31.99

$

0.285

Second Quarter

$

33.82

$

29.50

$

0.285

Third Quarter

$

36.31

$

30.24

$

0.285

Fourth Quarter

$

34.05

$

29.56

$

0.285

On January 15, 2008, PSEG s Board of Directors approved a two-for-one stock split of PSEG s outstanding shares of common stock. The stock split entitled each stockholder of record at the close of business on January 25, 2008 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed on February 4, 2008. All share and per share amounts included in this Form 10-K retroactively reflect the effect of the stock split.

On January 15, 2008, PSEG s Board of Directors also approved a $0.03 increase in its quarterly common stock dividend, from $0.2925 to $0.3225 per share for the first quarter of 2008. This reflects an indicated annual dividend rate of $1.29 per share. PSEG expects to continue to pay cash dividends on its common stock, however, the declaration and payment of future dividends to holders of PSEG common stock will be at the discretion of the Board of Directors and will depend upon many factors, including PSEG s financial condition, earnings, capital requirements of its business, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2007:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (#)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights ($)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (#)

Equity compensation plans approved by security holders

2,373,236

31.27

23,393,442

Equity compensation plans not approved by security holders

318,000

22.61

4,189,032

(A)

Total

2,691,236

30.25

27,582,474

(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 Note 17. Stock Based Compensation.

Power

All of Power s outstanding limited liability company membership interests are owned by PSEG. For additional information regarding Power s ability to pay dividends, see Item 7. MD&A Overview of 2007 and Future Outlook.

PSE&G

All of the common stock of PSE&G is owned by PSEG. For additional information regarding PSE&G s ability to continue to pay dividends, see Item 7. MD&A Overview of 2007 and Future Outlook.

ITEM 6.

SELECTED FINANCIAL DATA

PSEG

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

For the Years Ended December 31,

2007

2006

2005

2004

2003

(Millions, where applicable)

Operating Revenues

$

12,853

$

11,762

$

11,849

$

10,362

$

10,626

Income from Continuing Operations(A)

$

1,319

$

679

$

837

$

747

$

800

Net Income

$

1,335

$

739

$

661

$

726

$

1,160

Earnings per Share:

Income from Continuing Operations:

Basic(A)

$

2.60

$

1.35

$

1.74

$

1.57

$

1.76

Diluted(A)

$

2.59

$

1.34

$

1.71

$

1.56

$

1.75

Net Income:

Basic

$

2.63

$

1.47

$

1.38

$

1.53

$

2.54

Diluted

$

2.62

$

1.46

$

1.35

$

1.52

$

2.54

Dividends Declared per Share

$

1.17

$

1.14

$

1.12

$

1.10

$

1.08

As of December 31:

Total Assets

$

28,392

$

28,552

$

29,821

$

29,260

$

28,132

Long-Term Obligations(B)

$

8,709

$

10,147

$

11,035

$

12,392

$

12,462

(A)

Income from Continuing Operations for 2006 includes an after-tax charge of $178 million, or $0.35 per share related to the sale of RGE.

(B)

Includes capital lease obligations.

Power

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

PSE&G

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

For the Years Ended December 31,

2007

2006

2005

2004

2003

(Millions)

Operating Revenues

$

8,493

$

7,569

$

7,514

$

6,810

$

6,598

Income from Continuing Operations

$

380

$

265

$

348

$

346

$

247

Net Income

$

380

$

265

$

348

$

346

$

229

As of December 31:

Total Assets

$

14,637

$

14,553

$

14,297

$

13,586

$

13,177

Long-Term Obligations

$

4,632

$

4,711

$

4,745

$

4,877

$

5,129

ITEM 7.

MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

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

OVERVIEW OF 2007 AND FUTURE OUTLOOK

PSEG, Power and PSE&G

PSEG s business consists of four reportable segments, which are Power, PSE&G and the two direct subsidiaries of Energy Holdings L.L.C. (Energy Holdings), PSEG Global L.L.C. (Global) and PSEG Resources L.L.C. (Resources). The following discussion relates to the regions and markets in which PSEG s subsidiaries operate and compete, the corporate strategy for the conduct of PSEG s businesses within these markets and significant events that have occurred during 2007 and expectations for 2008 for Power, PSE&G and Energy Holdings, as well as the key factors that will drive the future performance of these businesses.

Stock Split

On January 15, 2008, PSEG s Board of Directors approved a two-for-one stock split of PSEG s outstanding shares of common stock. The stock split entitled each stockholder of record at the close of business on January 25, 2008 to receive one additional share for every outstanding share of common stock held. The additional shares resulting from the stock split were distributed on February 4, 2008. All share and per share amounts included in this Form 10-K retroactively reflect the effect of the stock split.

Power

Power is an electric generation and wholesale energy marketing and trading company that is focused on a generation market in the Northeast and Mid Atlantic U.S. Through its subsidiaries, Power seeks to produce low-cost energy through efficient operations of its nuclear, coal and gas-fired generation facilities, balance its generation production, fuel requirements and supply obligations through energy portfolio management and pursue disciplined growth. In addition to the electric generation business, Power s revenues include gas supply sales under the Basic Gas Supply Service (BGSS) contract with PSE&G.

Power s principal operating subsidiaries, PSEG Fossil LLC (Fossil), PSEG Nuclear LLC (Nuclear) and PSEG Energy Resources & Trade LLC (ER&T) are regulated by the FERC. ER&T and Fossil s subsidiary, PSEG Power Connecticut LLC, sell power at wholesale under Federal Energy Regulatory Commission (FERC)-approved market-based rate tariffs. Certain subsidiaries of Fossil are subject to state regulation and Nuclear is also subject to regulation by the Nuclear Regulatory Commission.

As a merchant generator, Power s profit is derived from selling under contract or on the spot market a range of diverse products such as energy, capacity, emissions credits, congestion credits and a series of energy-related products that the system operator uses to optimize the operation of the energy grid, known as ancillary services. Accordingly, the availability of Power s diverse fleet of generation units to produce these products as well as the prices of commodities, such as electricity, gas, nuclear fuel, coal and emissions, can have a material effect on Power s profitability. In recent years, the prices at which transactions are entered into for future delivery of these products, as evidenced through the market for forward contracts at points such as PJM Interconnection L.L.C. (PJM) West, have escalated considerably over historical prices. Broad market price increases such as these have had a positive effect on Power s results. Historically, Power s nuclear and coal-fired facilities have produced over 50% and 25% of Power s production, respectively. With the vast majority of its power sourced from these lower-cost units, the rise in electric prices has yielded higher margins for Power. Over a longer-term horizon, if these higher prices are sustained at levels reflective of what the current forward markets indicate, Power would have an attractive environment in which to contract for the sale of its anticipated output, allowing for potentially sustained higher profitability than recognized in prior years. These prices also increase the cost of replacement power, thereby placing risk on Power to operate the generating units to produce these products. Further, changes in the operation of Power s generating facilities, fuel and capacity prices, expected contract prices, capacity factors or other assumptions could materially affect its ability to meet earnings targets and/or liquidity requirements.

Power seeks to mitigate volatility in its results by contracting in advance for a significant portion of its anticipated electric output, capacity and fuel needs. Power believes this contracting strategy increases stability of earnings and cash flow.

Power seeks to sell a portion of its anticipated low-cost nuclear and coal-fired generation over a multi-year forward horizon, normally over a period of two to four years. As of February 15, 2008, Power has contracted for all of its anticipated 2008 nuclear and coal-fired generation, with 85% to 95% contracted for 2009 and 40% to 50% contracted for 2010, with a modest amount contracted beyond 2010.

Power has also entered into contracts for the future delivery of nuclear fuel and coal to support its contracted sales discussed above. As of February 15, 2008, Power had contracted for 100% of its annual nuclear uranium fuel needs through 2011 with decreasing percentages contracted through 2016. Power had also contracted for 85% to 95% of its anticipated coal needs, including transportation, for 2008, 75% to 85% for 2009, 55% to 65% for 2010 and modest amounts contracted beyond 2010. These estimated fuel needs are subject to change based upon the level of operation, and particular to coal, market demands and pricing, which has increased recently. Power has recently negotiated through some disruptions in the delivery of certain contracted coal. Power believes it can continue to manage its fuel sourcing needs in this dynamic market but cannot predict the impact that rising prices and potential increasing demand may have on its operations in the future.

By contrast, Power takes a more opportunistic approach in hedging its anticipated natural gas-fired generation. The generation from these units is less predictable, as these units are generally dispatched only when aggregate market demand has exceeded the supply provided by lower-cost units. The natural gas-fired units generally provide a lower contribution to the margin of Power than either the nuclear or coal units. Power will generally purchase natural gas as gas-fired generation is required to supply forward sale commitments.

In a changing market environment, this hedging strategy may cause Power s realized prices to be materially different than current market prices. At the present time, some of Power s existing contractual obligations, entered into during lower-priced periods, are anticipated to result in lower margins than would have been the case if no or little hedging activity had been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins in excess of those implied by the then current market.

Overview and Future Outlook

During 2007, Power continued to benefit from strong energy markets and sustained strong performance of its generating facilities. Going forward, Power expects continued strong margins as higher prices for its nuclear and coal-fired generation output are realized due to the rolling nature of its forward hedge positions and the expiration of older lower-priced power contracts.

In the electricity markets where Power participates, the pricing of electricity can vary by location. For example, prices may be higher in congested areas due to transmission constraints during peak demand periods, reflecting the bid prices of the higher cost units that are dispatched to meet demand. This typically occurs in the eastern portion of PJM, where many of Power s plants are located. At various times, depending upon its production and its obligations, these price differentials can serve to increase or decrease Power s profitability.

In PJM, the Reliability Pricing Model (RPM) provides generators with capacity payments for the reliability provided by their respective facilities. The Forward Capacity Market (FCM) in the New England Power Pool provides for similar reliability-based capacity payments. The FERC has approved the market changes in each of these markets, beginning on June 1, 2007 for the RPM transition period and on December 1, 2006 for the FCM transition period.

In October 2007, Power initiated planning activities with respect to the construction of 300 MW to 400 MW of new gas-fired peaking capacity that could be available to bid into PJM s RPM base residual auctions in 2008. Power estimates that the cost of this new construction could range from $250 million to $350 million. Power has requested that PJM perform feasibility studies to determine the system impact of adding incremental gas-fired capacity at some of its existing generating stations located in the constrained Eastern MAAC reliability region. Power s final decision whether or not to proceed with construction of any of these units would depend on estimated capital and interconnection costs, available siting and Power s ability to meet environmental permitting requirements. The costs related to these units are included in Power s forecasted capital expenditures.

Power is also currently exploring a number of other initiatives for potential growth or development such as the possibility of supplying power directly to New York City from Power s Bergen 2 generating facility or the potential to build new nuclear generation. There is no guarantee that such initiatives will be achieved since many issues would need to be considered, such as system reliability concerns, regulatory approvals and construction or development costs. Power does believe it has reasonable opportunities to grow its business.

A key factor in Power s ability to achieve its objectives is its ability to operate its nuclear and fossil stations at sufficient capacity factors to limit the need to purchase higher-priced electricity to satisfy its obligations. Power s ability to achieve its objectives will also depend on the continuation of reasonable capacity markets. Power must also be able to effectively manage its construction projects and continue to economically operate its generation facilities under increasingly stringent environmental requirements, including legislation, regulation and voluntary restrictions to address:

the control of carbon dioxide emissions to reduce the effects of global climate change and greenhouse gas;

other emissions such as nitrogen oxide, sulfur dioxide and mercury; and

the potential need for significant upgrades to existing intake structures and cooling systems at its larger once-through cooled plants, including Salem, Hudson, Mercer, Sewaren, New Haven and Bridgeport.

Power has two large environmental back-end technology projects underway at its Mercer and Hudson coal plants aggregating approximately $1.1 billion in capital costs. These projects are scheduled to be completed by the end of 2010. Power is focused on completing these projects on schedule and within the established budgets, but faces many risks typically involved in managing large construction projects.

In addition, with an increase in competition and market complexity and constantly changing forward prices, there is no assurance that Power will be able to contract its output at attractive prices. While these increases may have a potentially significant beneficial impact on margins, they could also raise any replacement power costs that Power may incur in the event of unanticipated outages, and could also further increase liquidity requirements as a result of contract obligations. For additional information on liquidity requirements, see Liquidity and Capital Resources.

Power could also be impacted by a number of events, including regulatory or legislative actions favoring non-competitive markets, energy efficiency initiatives, and regulatory policies favoring the construction of rate-based transmission that may result in increased imports of generation, which may be subject to less stringent environmental regulation, into areas served by Power s generation assets. Further, some of the market-based mechanisms in which Power participates, including Basic Generation Service (BGS) auctions and RPM capacity payments, are at times the subject of review or discussion by some of the participants in the New Jersey and federal regulatory and political arenas and the PJM market monitor. Power can provide no assurance that these mechanisms will continue to exist in their current form for the foreseeable future.

PSE&G

PSE&G operates as an electric and gas public utility in New Jersey under cost-based regulation by the New Jersey Board of Public Utilities (BPU) for its distribution operations and by the FERC for its electric transmission and wholesale sales operations.

Consequently, the earnings of PSE&G are largely determined by the regulation of its rates by those agencies. The BPU approved rate increases for gas delivery service in November 2006. Under the terms of the settlement of its electric and gas base rate cases, PSE&G is required to file jointly for any gas and electric petition for future base rate increases and no base rate changes may become effective before November 15, 2009.

Overview and Future Outlook

In February 2007, the BPU approved the results of New Jersey s annual BGS-Fixed Price (FP) and BGS-Commercial and Industrial Energy Price auctions and PSE&G successfully secured contracts to provide the electricity requirements for the majority of its customers needs.

The Governor of New Jersey has directed the BPU, in partnership with other New Jersey agencies, to develop an Energy Master Plan (EMP) that reduces energy consumption while emphasizing energy efficiency, conservation and renewable energy resources to meet New Jersey s future energy demands without increasing its reliance on non-renewable resources.

In conjunction with these efforts, on April 19, 2007, PSE&G filed a proposal with the BPU designed to spur investment in solar power in New Jersey and meet energy goals under the EMP. Under the plan, PSE&G would invest approximately $100 million over two years following BPU approval of the plan to help finance the installation of solar systems throughout its service area. Under the Solar Energy Program, PSE&G would loan money to customers in its electric service territory for the installation of solar photovoltaic systems on the customers premises. The borrowers would repay the loans over a period of either 10 years (for residential customer loans) or 15 years (for all other loans) by providing PSE&G with solar renewable energy certificates (SRECs). Borrowers also have the option to repay the loans with cash. PSE&G has proposed that it be allowed to earn a fair return on and of its investment, and fully recover its administrative costs to implement the Solar Energy Program, through its regulated rates.

If approved by the BPU, the initiative could begin in the second quarter of 2008 and support 30 MW of solar power in the following two years, fulfilling approximately 50% of the BPU s Renewal Portfolio Standard requirements in PSE&G s service area for energy years 2009 and 2010. On July 12, 2007, the BPU established a schedule for consideration of this proposal. PSE&G has held a series of stakeholder meetings to discuss program details with interested parties. Settlement discussions are ongoing, with a BPU decision expected in early 2008. The outcome of this proceeding cannot be predicted at this time.

On June 8, 2007, PSE&G endorsed the construction of three new 500 kV transmission lines intended to significantly improve the reliability of the electrical grid serving New Jersey customers. On June 22, 2007, PJM s Board of Managers approved construction of one of the proposed lines and assigned construction responsibility to PSE&G, Pennsylvania Power and Light and FirstEnergy Corporation (FirstEnergy) for their respective service territories. On October 9, 2007, PJM provided a formal letter notification to PSE&G identifying PSE&G as the responsible party for the construction of both its portion of the new line and the portion originally assigned to FirstEnergy in New Jersey. The estimated cost of PSE&G s portion of this construction project is between $600 million and $650 million. PSE&G s costs will go into transmission rate base, subject to regulatory approval, and can be expected to have a positive impact on revenues and earnings for PSE&G. In addition, the U.S. Department of Energy has now designated the Mid-Atlantic Area Corridor, which encompasses all of New Jersey, as a National Interest Electric Transmission Corridor to which the FERC back-stop eminent domain authority will attach.

The two other lines which PSE&G has endorsed have not yet been submitted to PJM for approval, as required by PJM rules, but PSE&G believes that construction of these lines, which would follow existing transmission rights-of-way, are needed to enhance the reliability of the transmission system.

PJM has proposed significant changes to the rules establishing how economic transmission gets built within PJM. Economic transmission is transmission that is being built to reduce economic congestion on the system, as congestion can result in higher electricity prices paid by consumers located within congested areas. PJM proposes to forecast congestion levels well into the future and to use these forecasts as the basis for determining the benefits of an economic transmission project. PJM s proposal is focused on rate-based rather than market conditions solutions. Power and PSE&G have actively participated in the FERC proceeding that is still considering the specifics of PJM s proposal.

On June 1, 2007, new electric BGS-FP rates went into effect with an expected increase of approximately 12% to residential customers bills. There was no change to the BGSS residential rate during 2007.

As a result of the February 2008 auction new BGS-FP rates will increase the average residential customers bill by approximately 12% effective June 2008.

The risks to PSE&G s business generally relate to the treatment of the various rate and other issues by the state and federal regulatory agencies, specifically the BPU and the FERC. PSE&G s success will depend, in part, on its ability to attain a reasonable rate of return, continue cost containment initiatives, maintain system reliability and safety levels, continue recovery of the regulatory assets it has deferred and attain an adequate return on the investments it plans to make in its electric and gas transmission and distribution system and the level of recovery of distribution revenues in light of customer demand and conservation efforts. Also, PSE&G s recent incentive rate treatment request for the Susquehanna-Roseland line and classifying the new 69 kV facilities as transmission would result in improvements in reliability and more expeditious rate treatment for these facilities.

The FERC s ruling regarding PJM long-term transmission rate design, which remains subject to rehearing, benefits PSE&G customers by preserving lower rates than would likely be in effect under proposed rate design modifications. Since PSE&G earns no margin on the commodity portion of its electric and gas sales through tariff agreements, there is no anticipated commodity price volatility for PSE&G; however, commodity costs continue to put upward pressure on customer charges.

Global

Overview and Future Outlook

Global has reduced its international risk by monetizing the majority of its international investments.

On October 17, 2007, Global closed on the sale of its interests in Electroandes S.A. (Electroandes), its 180 MW hydro-electric generation and transmission company in Peru to a wholly owned subsidiary of

Statkraft Norfund Power Invest (SN Power) of Norway for a total purchase price of approximately $390 million (subject to working capital and other adjustments), including the assumption of approximately $108 million of debt. After-tax net cash proceeds, including dividends paid prior to closing, were approximately $220 million.

On December 14, 2007, Global closed on the sale its 50% ownership interest in Chilquinta Energia S.A. (Chilquinta), an electric distribution company in Chile, and its 38% ownership of Luz del Sur S.A.A. (LDS), an electric distribution company in Peru to a subsidiary of AEI (formerly Ashmore Energy International), for approximately $685 million. After-tax net cash proceeds were approximately $480 million.

On December 18, 2007, PSEG announced its intention to sell its equity interest in the SAESA Group. The SAESA Group is Global s largest remaining international investment, consisting of four distribution companies, one transmission company and a generation facility located in Chile.

For additional information on Electroandes, Chilquinta, LDS and SAESA, see Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments.

Domestically, Global has investments in power producers that own and operate electric generation in Texas, California and Hawaii, with smaller investments in New Hampshire and Pennsylvania. Global expects these operations to continue to perform well and provide the opportunity for growth. As a merchant generation business with a load-following asset profile, Global s largest domestic investment is in two generating facilities in Texas, and, as such, its success will be driven by the efficient operation of those plants and by changes in market conditions, particularly projected market heat rates and weather. Global seeks to sell its output from its Texas facilities by entering into a mix of contracts consisting of standard on-peak calendar transactions and structured contracts normally selling forward 30% to 50% of its available capacity with the balance sold during the year and in the daily balancing and ancillary service markets. Global s results from its investments in Texas are also impacted by the recognition of unrealized mark-to-market (MTM) gains and losses on fixed-price contracts that expire in 2010.

Beginning in December 2008, the Electric Reliability Council of Texas (ERCOT) will transition from a zonal market to a nodal wholesale market. The redesigned grid will consist of more than 4,000 nodes replacing the current four congestion management zones. The implementation of the nodal market design is expected to deliver improved price signals, improved dispatch efficiencies and direct assignment of local congestion. PSEG is currently evaluating the potential impact this change will have on its Texas generation facilities.

Global is also continuing to explore options for monetizing its other remaining international investments in Italy, Venezuela and India, which total approximately $123 million. In June 2007, Global restarted Bioenergie S.p.A. s (Bioenergie) San Marco biomass generation facility after a seven-month outage due to a pending criminal investigation regarding allegations of violations of the facility s air permit. With respect to Global s investment in Turboven Company Inc. (Turboven), Global recently entered into preliminary valuation discussions with the government of Venezuela as part of the nationalization efforts which are ongoing. Based upon a recent review of the circumstances, an impairment charge of $7 million, after-tax, was recorded in September 2007 to further write down Global s Venezuelan investments. No assurances can be given as to whether Global can recover the current book value of the investments in Venezuela. Global s investment in India is currently more stable than in prior years as evidenced by dividend payments of $6 million in 2007 and $2 million during 2006. The value of Global s investment in PPN Power Generating Company Limited (PPN), India was adjusted down by $2 million, after-tax, to reflect the estimated current market value of PPN.

Global is pursuing the potential development of wind, biomass and solar projects, primarily in PSEG s core markets.

Resources

Overview and Future Outlook

Resources primarily has invested in energy-related leveraged leases. Resources is focused on maintaining its current investment portfolio and does not expect to make any new investments. Resources future performance is subject to tax risks related to its lease transactions. See Note 12. Commitments and Contingent Liabilities for further discussion.

PSEG faces significant risk at Resources related to the tax treatment of uncertain tax positions which was impacted by new accounting guidance under FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48) and FASB Staff Position No. FSP 13-2, Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction (FSP 13-2), both of which were effective as of January 1, 2007. This new guidance also reduced PSEG s earnings by approximately $30 million in 2007 as compared to 2006. Resources future earnings could also be impacted by changes to uncertain tax positions as determined by changes in substantive tax law and tax audit results, including resolution of tax audit claims associated with its leveraged lease transactions. See Note 2. Recent Accounting Standards and Note 12. Commitments and Contingent Liabilities for further discussion.

RESULTS OF OPERATIONS

Earnings (Losses)

Years Ended December 31,

2007

2006

2005

(Millions)

Power

$

949

$

515

$

434

PSE&G

380

265

348

Global (A)

31

(84

)

63

Resources

58

63

92

Other(B)

(99

)

(80

)

(100

)

PSEG Income from Continuing Operations

1,319

679

837

Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal(C)

16

60

(159

)

Cumulative Effect of a Change in Accounting Principle(D)

(17

)

PSEG Net Income

$

1,335

$

739

$

661

Earnings Per Share (Diluted)

Years Ended December 31,

2007

2006

2005

PSEG Income from Continuing Operations

$

2.59

$

1.34

$

1.71

Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal(C)

0.03

0.12

(0.33

)

Cumulative Effect of a Change in Accounting Principle(E)

(0.03

)

PSEG Net Income

$

2.62

$

1.46

$

1.35

(A)

Global s Income from Continuing Operations for 2007 includes the after-tax loss of $23 million resulting from the sale of Chilquinta and LDS and for 2006 includes the $178 million after-tax loss on the sale of Rio Grande Energia S.A. (RGE).

(B)

Other activities include non-segment amounts of PSEG (as parent company) and its subsidiaries and intercompany eliminations. Specific amounts include interest on certain financing transactions and certain administrative and general expenses at PSEG and Energy Holdings (as parent companies).

(C)

Includes Discontinued Operations of Lawrenceburg, the SAESA Group and Electroandes in 2007, 2006 and 2005 and Elektrocieplownia Chorzow Elcho Sp. Z o.o. (Elcho) and Elektrownia Skawina SA (Skawina) in 2006 and 2005 as well as the gain on the sale of Electroandes in 2007, the gains on the sales of Elcho and Skawina in 2006 and the loss on the sale of Waterford in 2005. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments.

(D)

Relates to the adoption in 2005 of FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations. (FIN 47). See Note 3. Asset Retirement Obligations.

PSEG

For the Years
Ended December 31,

2007 vs 2006

2006 vs 2005

2007

2006

2005

Increase (Decrease)

%

Increase (Decrease)

%

(Millions)

(Millions)

(Millions)

Operating Revenues

$

12,853

$

11,762

$

11,849

$

1,091

9

$

(87

)

(1

)

Energy Costs

$

6,523

$

6,553

$

6,882

$

(30

)

N/A

$

(329

)

(5

)

Operation and Maintenance

$

2,419

$

2,221

$

2,224

$

198

9

$

(3

)

N/A

Write-down of Assets

$

16

$

318

$

$

(302

)

(95

)

$

318

N/A

Depreciation and Amortization

$

783

$

811

$

714

$

(28

)

(3

)

$

97

14

Income from Equity Method Investments

$

116

$

120

$

124

$

(4

)

(3

)

$

(4

)

(3

)

Other Income and Deductions

$

23

$

88

$

144

$

(65

)

(74

)

$

(56

)

(39

)

Interest Expense

$

(729

)

$

(791

)

$

(766

)

$

(62

)

(8

)

$

25

3

Income Tax Expense

$

(1,060

)

$

(460

)

$

(549

)

$

600

N/A

$

(89

)

(16

)

Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal, net of tax

$

16

$

60

$

(159

)

$

(44

)

(73

)

$

219

N/A

Cumulative Effect of a Change in Accounting Principle, net of tax

$

$

$

(17

)

$

(17

)

N/A

$

17

N/A

PSEG s results of operations are primarily comprised of the results of operations of its operating subsidiaries, PSE&G, Power and Energy Holdings, excluding changes related to intercompany transactions, which are eliminated in consolidation. It also includes certain financing costs at the parent company. For additional information on intercompany transactions, see Note 21. Related-Party Transactions. For a discussion of the causes for the variances at PSEG in the table above, see the discussions for Power, PSE&G and Energy Holdings that follow.

Power

For the year ended December 31, 2007, Power had Net Income of $941 million, an increase of $665 million as compared to the year ended December 31, 2006. Excluding the Losses from Discontinued Operations of Lawrenceburg of $8 million and $239 million in 2007 and 2006, respectively, Income from Continuing Operations for the year ended December 31, 2007 was $949 million, an increase of $434 million as compared to 2006. The primary reasons for the increase in Income from Continuing Operations were higher prices realized from new contracts, including BGS contracts, combined with higher sales volumes and lower generation costs. Improved margins and higher sales volumes under the BGSS contract due to a colder winter heating season and more favorable fuel pricing in 2007 also contributed to the increase. The increase in Income from Continuing Operations also included the recognition of non-trading MTM losses of $6 million, after-tax, in 2007 as compared to $1 million of after- tax MTM losses in 2006.

For the year ended December 31, 2006, Power had Net Income of $276 million, an increase of $84 million as compared to the year ended December 31, 2005. Excluding Losses from Discontinued Operations of Lawrenceburg and Waterford of $239 million and $226 million in 2006 and 2005, respectively, and a $16 million charge recorded for the cumulative effect adjustment of adopting FIN 47 in 2005, Income from Continuing Operations was $515 million for the year ended December 31, 2007, an increase of $81 million as compared to 2006. The increase primarily resulted from higher BGS contract prices and higher sales volumes in the various power pools, supported by improved nuclear operations and the commencement of commercial operations at Linden in May 2006 and at the Bethlehem Energy Center (BEC) in July 2005 and lower generation costs due to lower pool prices and lower demand under BGS contracts. Power also had lower non-trading losses, which were approximately $1 million in 2006 as compared to $8 million in 2005. Power s increased earnings were partially offset by reduced margins on BGSS, as market prices for natural gas declined from historically high price levels experienced in the second half of 2005 while the cost of gas in inventory was reasonably stable, and lower demand in 2006 due to a warmer winter heating system and customer conservation. Power s 2006 earnings were also affected by a $44 million pre-tax write-down of four gas turbines, which were sold in April 2007, a $30 million after-tax decrease in Income from the Nuclear Decommissioning Trust (NDT) Funds and higher Operation and Maintenance Costs, Depreciation and Amortization and Interest Expense related to operation of the Linden and BEC facilities.

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

**For the Years
Ended December 31,**

2007 vs 2006

2006 vs 2005

2007

2006

2005

Increase (Decrease)

%

Increase (Decrease)

%

(Millions)

(Millions)

(Millions)

Operating Revenues

$

6,796

$

6,057

$

6,027

$

739

12

$

30

N/A

Energy Costs

$

3,975

$

3,955

$

4,266

$

20

1

$

(311

)

(7

)

Operation and Maintenance

$

1,001

$

958

$

939

$

43

4

$

19

2

Write-Down of Assets

$

$

44

$

$

(44

)

(100

)

$

44

N/A

Depreciation and Amortization

$

140

$

140

$

114

$

N/A

$

26

23

Other Income and Deductions

$

69

$

66

$

144

$

3

5

$

(78

)

(54

)

Interest Expense

$

(159

)

$

(148

)

$

(100

)

$

11

7

$

48

48

Income Tax Expense

$

(641

)

$

(363

)

$

(318

)

$

278

77

$

45

14

Loss from Discontinued Operations, including Loss on Disposal, net of tax

$

(8

)

$

(239

)

$

(226

)

$

(231

)

(97

)

$

13

6

Cumulative Effect of a Change in Accounting Principle, net of tax

$

$

$

(16

)

$

N/A

$

16

N/A

Operating Revenues

The $739 million increase for the year ended December 31, 2007 as compared to 2006 was due to increases of $416 million in generation revenues and $349 million in gas supply revenues, which were partially offset by $26 million in lower trading revenues.

The $30 million increase for the year ended December 31, 2006 as compared to 2005 was due to increases of $238 million in generation revenues and $27 million in trading revenues, which were partially offset by a decrease of $235 million in gas supply revenues.

Generation

The $416 million increase in generation revenues for the year ended December 31, 2007, as compared to 2006, was primarily due to higher revenues of $355 million from higher prices on BGS fixed- price contracts. Also contributing to the increase was $149 million from higher capacity prices resulting from the changes in the capacity markets in PJM and Connecticut, which resulted in $47 million in reduced RMR revenues in these markets. Power also had increased revenues resulting from more generation being sold into the various pools in which it operated following the expiration of certain of its wholesale power contracts. The increased revenues from sales into the various pools offset the reduction in wholesale contract revenues.

The $238 million increase in generation revenues for the year ended December 31, 2006, as compared to 2005, was primarily due to an increase of $238 million from higher sales volumes in the various power pools, supported by improved nuclear operations and the commencement of the commercial operations of Linden in May 2006 and BEC in July 2005, partially offset by lower pool prices. Also contributing to the increase was $92 million of higher BGS contract revenues due to higher contract prices which were partly offset by a reduction in load being served under the fixed-price BGS contracts and termination of BGS hourly contracts in May 2006. The increases were partially offset by a decrease of $58 million due to certain wholesale contracts ending in 2005 and early 2006 and $33 million of unrealized losses on asset-backed electric forward contracts.

Gas Supply

The $349 increase in gas supply revenues for the year ended December 31, 2007, as compared to 2006, includes $248 million resulting from higher sales volumes under the BGSS contract, largely due to colder average temperatures in the 2007 winter heating season. The increase was also attributable to the recognition of gains of $69 million on financial hedging transactions. The remaining increases were primarily due to increased pricing and volumes sold to other gas distributors and increased revenues received for balancing and storage due to higher sales volumes and higher tariff rates that became effective in January 2007.

The $235 million decrease in gas supply revenues for the year ended December 31, 2006, as compared to 2005, was primarily due to decreases of $334 million due to lower demand under the BGSS contract in 2006 due to a warmer winter heating season and improved customer conservation in 2006 and $94 million in decreased prices and gas volumes and pipeline capacity sold to other gas customers. The decreases were partially offset by an increase of $188 million due to higher prices under the BGSS contract.

Trading

The $26 million decrease in trading revenues for the year ended December 31, 2007, as compared to 2006, was due mainly to the absence of gains related to emissions credits that were realized in 2006.

The $27 million increase in trading revenues for the year ended December 31, 2006, as compared to 2005, was principally due to higher realized gains related to emissions credits.

Operating Expenses

Energy Costs

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.

The $20 million increase for the year ended December 31, 2007, as compared to 2006, was due to a $247 million increase in gas costs offset by a decrease of $227 million in generation costs. The increase in gas costs reflected a $245 million increase due to a higher volume of gas sold to satisfy Power s BGSS obligations and an increase of $16 million due to the recognition of losses in 2007 coupled with gains in 2006 related to financial hedging transactions. The decrease in generation costs reflected decreases of $275 million due to lower pool purchases, primarily resulting from reduced load obligations in Connecticut following the expiration of a wholesale power contract in 2006, combined with $61 million in lower congestion and transmission costs. These decreases were partially offset by an increase of $154 million due to higher volumes of fuel purchases, primarily natural gas, as these units ran more during 2007.

The $311 million decrease for the year ended December 31, 2006, as compared to 2005, was primarily due to decreases of $267 million from lower pool prices and lower demand under BGS contracts, $144 million from a reduced volume of gas purchased to satisfy Power s BGSS obligations, partially offset by higher gas prices related to inventory for the 2005/2006 winter heating season, and $58 million due to favorable pricing of fuel-related asset-backed transactions in 2006. These decreases were partially offset by $80 million of losses realized on gas hedges in 2006, an increase of $42 million in fuel costs and an increase of $35 million in transmission fees. The increase in fuel costs was largely due to higher volumes of gas purchased to meet increased production by the gas-fired plants, including Linden and BEC, and higher oil prices, partially offset by lower gas prices during 2006 and a lower volume of oil purchases due to reduced running times of certain of the oil-fired plants in 2006.

Operation and Maintenance

The $43 million increase for the year ended December 31, 2007, as compared to 2006, was principally due to costs incurred in 2007 related to various maintenance projects at certain fossil stations, mainly Hudson and Mercer.

The $19 million increase for the year ended December 31, 2006, as compared to 2005, was principally due to higher maintenance costs of $60 million related to certain of the fossil plants and scheduled outages at the nuclear units. These increases were partially offset by the absence of a $14 million restructuring charge recorded in 2005 related to Nuclear s workforce realignment plan, a decrease of $10 million in payroll and benefits due to a reduction in employees and a decrease of $14 million in fees paid to Services for information technology and various administrative services.

Write-Down of Assets

The $44 million write-down of assets recorded in 2006 related to four turbines for which Power had no immediate use and which Power sold in April 2007. For additional information, see Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments.

Depreciation and Amortization

There was no material change in Depreciation and Amortization for the year ended December 31, 2007 as compared to 2006. The $26 million increase for the year ended December 31, 2006, as compared to 2005, was primarily due to the Linden and BEC plants being placed into service in May 2006 and July 2005, respectively.

Other Income and Deductions

The $3 million increase in Other Income and Deductions for the year ended December 31, 2007 as compared to 2006, was principally due to increased realized income of $76 million related to the NDT Funds, the absence of $14 million of penalties referenced below that were recorded in 2006 and increased interest income of $13 million from short-term loans to PSEG (as parent company). These increases were partially offset by increased realized losses of $34 million and increased charges of $58 million recorded in 2007 for other-than-temporary impairments related to the NDT Fund securities and the absence of $6 million of expense reversals recorded in 2006 related to certain excess liability reserves.

The $78 million decrease for the year ended December 31, 2006, as compared to 2005, was primarily due to decreased net realized income of $29 million and increased realized losses of $19 million related to the NDT Funds. Also contributing to the decrease were charges recorded in 2006 of $14 million for an other-than-temporary impairment of certain NDT Fund securities and $14 million for penalties related to negotiations concerning environmental concerns and an alternate pollution reduction plan for Power s Hudson unit.

Interest Expense

Interest Expense increased $11 million for the year ended December 31, 2007, as compared to 2006, due primarily to an increase in interest expense of $20 million due to the reclassification of Interest Expense to Discontinued Operations of the Lawrenceburg facility for year ended December 31, 2006 and through the sale of Lawrenceburg in May 2007 combined with an $8 million increase due to lower capitalized interest in 2007 since the Linden construction was completed in May 2006. These increases were partially offset by the absence of $10 million of interest expense in 2007 due to the maturity of the 6.87% Senior Notes in April 2006, as well as decreases in interest incurred on lower average short-term borrowings from Enterprise and lower commitment and letter of credit fees.

The $48 million increase for the year ended December 31, 2006, as compared to 2005, was due primarily to lower capitalized interest costs in 2006 related to commencement of operations of the Linden and BEC facilities.

Income Tax Expense

Income Taxes increased in both 2007 and 2006, primarily due to higher pre-tax income.

Loss from Discontinued Operations, including Loss on Disposal, net of tax

On May 16, 2007, Power completed the sale of its Lawrenceburg generation facility. The sale price for the facility and inventory was $325 million. The transaction resulted in an after-tax charge to Power s earnings of $208 million and was reflected as a charge to Discontinued Operations in the fourth quarter of 2006. Losses from Discontinued Operations of Lawrenceburg, not including the Loss of Disposal, were $8 million, $31 million and $28 million for the years ended December 31, 2007, 2006 and 2005, respectively.

On May 27, 2005, Power reached an agreement to sell its Waterford generation facility for $220 million and recognized an estimated loss on disposal of $177 million, net of tax, for the initial write-down of its carrying amount of Waterford to its fair value less cost to sell. On September 28, 2005, Power completed the sale of Waterford and recognized an additional loss of $1 million. Losses from Discontinued Operations of Waterford, not including the

Loss of Disposal, were $20 million for the year ended December 31, 2005.

See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments for additional information.

Cumulative Effect of a Change in Accounting Principle, net of tax

For the year ended December 31, 2005, Power recorded an after-tax loss in the amount of $16 million due to the required recording of a liability for the fair value of asset-retirement costs primarily related to its generation plants under FIN 47, which was adopted in December 2005.

PSE&G

For the year ended December 31, 2007, PSE&G had Net Income of $380 million, an increase of $115 million as compared to the year ended December 31, 2006. About $69 million of the increase was due to the full year effect of the electric and gas base rate increases in November 2006. The return to a normal heating load (degree days were 16% higher in 2007 compared to 2006) for gas and a 2% growth in electric sales added $60 million to net income. Offsetting these increases was a less than 2% increase in controllable Operation and Maintenance.

For the year ended December 31, 2006, PSE&G had Net Income of $265 million, a decrease of $83 million as compared to the year ended December 31, 2005. This decrease was primarily due to delayed decisions in the electric and gas base rate cases combined with the decline in electric and gas delivery volumes. In 2006, delivery volumes for gas and electric decreased 10% and 3%, respectively. The weather was the primary cause of these declines with a drop of 16% in the number of degree days impacting gas. Gas commodity prices were extremely high early in 2006, which also contributed to a further decline in weather normalized sales. Thermal Heat Index hours were normal in 2006 but 18% less than 2005, negatively impacting electric sales.

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

For the Years Ended December 31,

2007 vs 2006

2006 vs 2005

2007

2006

2005

Increase (Decrease)

%

Increase (Decrease)

%

(Millions)

(Millions)

(Millions)

Operating Revenues

$

8,493

$

7,569

$

7,514

$

924

12

$

55

1

Energy Costs

$

5,498

$

4,884

$

4,756

$

614

13

$

128

3

Operation and Maintenance

$

1,308

$

1,160

$

1,151

$

148

13

$

9

1

Depreciation and Amortization

$

591

$

620

$

553

$

(29

)

(5

)

$

67

12

Other Income and Deductions

$

12

$

22

$

12

$

(10

)

(45

)

$

10

83

Interest Expense

$

(332

)

$

(346

)

$

(342

)

$

(14

)

(4

)

$

4

1

Income Tax Expense

$

(257

)

$

(183

)

$

(235

)

$

74

40

$

(52

)

(22

)

Operating Revenues

PSE&G has three sources of revenue: commodity revenues from the sales of energy to customers and in the PJM spot market; delivery revenues from the transmission and distribution of energy through its system; and other operating revenues from the provision of various services.

PSE&G makes no margin on gas commodity sales as the costs are passed through to customers. The difference between the gas costs paid under the requirements contract for residential customers and the revenues received from residential customers is deferred and collected from or returned to customers in future periods. Gas commodity prices fluctuate monthly for commercial and industrial customers and annually through the BGSS tariff for residential customers. In addition, for residential gas customers, PSE&G has the ability to adjust rates upward two additional times and downward at any time, if warranted, between annual BGSS proceedings.

PSE&G makes no margin on electric commodity sales as the costs are passed through to customers. PSE&G secures its electric commodity through the annual BGS auction. Electric commodity supply prices are set based on the results of these auctions for residential and smaller industrial and commercial customers, and are translated into seasonally-adjusted fixed rates. Electric supply for larger industrial and commercial customers is provided at a rate principally based on the hourly PJM real-time energy price. Customers may obtain their electric supply through either the BGS default electric supply service or through competitive third-party electric suppliers, and the majority of the customers subject to hourly pricing are currently receiving electric supply from third-party suppliers. Any differences between amounts paid by PSE&G to BGS suppliers for electric commodity, and the amounts of electric commodity revenue collected from customers is deferred and collected or returned to customers in subsequent months.

PSE&G also purchases electric commodity from several Non-Utility Generation (NUG) facilities which is resold in the PJM market. Most of the NUG contracts are priced above market under long-term contracts. PSE&G recoups the difference in price through the Non-Utility Generation Clause (NGC).

The $924 million increase for the year ended December 31, 2007, as compared to 2006, was due to increases of $613 million in commodity revenues and $301 million in delivery revenues, described below and $10 million in other operating revenues, primarily related to appliance service contracts.

The $55 million increase for the year ended December 31, 2006, as compared to 2005 was due to increases of $78 million in commodity revenues and $3 million in other operating revenues, offset by a decrease of $26 million in delivery revenues.

Commodity

The $613 million increase in commodity-related revenues for the year ended December 31, 2007, as compared to 2006, was due to increases of $510 million and $103 million in electric and gas revenues, respectively. The electric increase was due to $541 million in higher BGS revenues (higher auction prices of $484 million plus increased sales of $57 million), $44 million in higher NUG prices, offset by a $74 million decrease in the NGC revenues ($78 million in lower prices due to a March 2007 rate change offset by $4 million in higher volumes). The gas increase was primarily due to $240 million in increased sales due to weather offset by $137 million in lower BGSS prices.

The $78 million increase in commodity revenues for the year ended December 31, 2006, as compared to 2005, was due to an increase in electric commodity revenues of $213 million, offset by a decrease of $135 million in gas commodity revenues. The increase in electric revenues was due to $299 million in higher BGS revenues (higher auction prices of $346 million offset by reduced sales of $47 million) offset by $85 million in lower NUG revenues (lower prices of $82 million and by $3 million for lower volumes). The gas decrease was due to $317 million in lower volumes due to weather and $58 million due to the expiration of the Third Party Shopping Incentive Clause in July 2005. There was a corresponding $58 million increase in delivery revenues. These were offset by $240 million in higher BGSS prices.

Delivery

The $301 million increase in delivery revenues for the year ended December 31, 2007, as compared to 2006, was due to increases of $169 million and $132 million in electric and gas revenues, respectively. The electric increase was due primarily to $83 million for increased SBC rates, $42 million in rate relief effective November 9, 2006 and $44 million in increased sales and demands primarily due to weather. PSE&G retains no margins from SBC collections as the revenues are offset in operating expenses below. The gas increase was due to $67 million in increased sales primarily due to weather, $39 million due to the SBC rate increases on November 1, 2006 and March 9, 2007 and $31 million due to rate relief effective November 9, 2006.

The $26 million decrease in delivery revenues for the year ended December 31, 2006, as compared to 2005, was due to a $27 million decrease in gas offset by a $1 million increase in electric revenues. The gas decrease was due to $101 million in lower volumes primarily due to weather offset by $74 million in increased prices, $58 million of which was due to the expiration of the Third Party Shopping Incentive Clause in July 2005, described above in commodity revenues, $8 million due to rate relief effective November 9, 2006 and $8 million due to the SBC November 1, 2006 rate increase. The electric increase was due primarily to $13 million in higher securitization tariff rates and $8 million from a rate increase effective November 9, 2006, offset by $20 million in lower volumes due to weather.

Operating Expenses

Energy Costs

The $614 million increase for the year ended December 31, 2007, as compared to the same period in 2006, was comprised of increases of $512 million and $102 million in electric and gas costs, respectively. The electric increase was due to $453 million or 18% in higher prices for BGS and NUG purchases and $59 million or 2% in higher BGS volumes due to weather. The gas increase was caused by a $239 million or 11% increase in sales volumes due primarily to weather offset by $137 million in lower prices.

The $128 million increase for the year ended December 31, 2006, as compared to 2005, was comprised of an increase of $211 million in electric costs offset by a decrease of $83 million in gas costs. The electric increase was caused by $255 million or 16% in higher prices for BGS and NUG purchases offset by $47 million in lower BGS volumes due to weather. The gas decrease was caused by a $362 million or 17% decrease in sales volumes due to weather and $8 million due to the expiration of the Gas Cost Underrecovery Adjustment clause in January 2005, offset by $287 million or 11% in higher prices.

Operation and Maintenance

The $148 million increase for the year ended December 31, 2007, as compared to 2006, was due primarily to increased SBC expenses of $132 million, resulting from rate increases in November 2006 and March 2007, increased payroll of $16 million, a higher reserve for injuries and damages of $10 million and $5 million for outside services. Offsetting the increases was $19 million in lower pension expense. The increased SBC expenses were offset in delivery revenues with no impact on net income.

The $9 million increase for the year ended December 31, 2006, as compared to 2005, was due to $9 million in increased labor and fringe benefits due to increased wages and Other Postretirement Benefits costs and $7 million in increased bad debt expense. These increases were offset by decreases of $3 million in injuries and damage claims and $2 million in write offs and $2 million in Net Operating Loss purchases.

Depreciation and Amortization

The $29 million decrease for the year ended December 31, 2007, as compared to 2006, was due primarily to decreases of $30 million due to revised plant depreciation rates and $11 million due to lower cost of removal rates, both resulting from the November 2006 rate case. Also contributing to the decrease was $8 million due to software previously amortized in 2006. This was offset by increases of $11 million due to amortization of regulatory assets and $9 million due to additional plant in service.

The $67 million increase for the year ended December 31, 2006, as compared to 2005, was comprised of increases of $70 million from the expiration of an excess depreciation credit, $6 million due to amortization of regulatory assets and $3 million due to additional plant in service. These increases were offset by decreases of $5 million due to revised plant depreciation and cost of removal rates, $3 million due to software amortization and $3 million due to the amortization of the Remediation Adjustment Clause.

Other Income and Deductions

The $10 million decrease for the year ended December 31, 2007, as compared to 2006, was due primarily to $7 million reduction in income tax gross-ups on contributions in aid of construction (CIAC). CIAC is taxable and PSE&G recognizes the gross-up as income when collected. Also contributing to the decrease was $2 million in lower investment income and $1 million in increased donations.

The $10 million increase for the year ended December 31, 2006, as compared to 2005, was due to an $8 million income tax gross-up on CIAC in 2006. CIAC are taxable and PSE&G recognizes the gross- up as income when collected. Also included are increases of $1 million of short-term interest income and $1 million in gains on the sale of excess property.

Interest Expense

The $14 million decrease for the year ended December 31, 2007, as compared to 2006, was due primarily to lower interest expense of $12 million related to settlement of IRS Audits in 2006 and lower interest on regulatory clauses of $7 million, offset by $5 million in increased long-term debt due to new debt issuances in December 2006 and May 2007.

Income Tax Expense

The $74 million increase for the year ended December 31, 2007, as compared to 2006, was primarily due to $77 million on higher pre-tax income offset by $3 million in various tax adjustments and tax credits.

The $52 million decrease for the year ended December 31, 2006, as compared to 2005, was due to $55 million on lower pre-tax income offset by $3 million in various flow-through adjustments.

Energy Holdings

For the year ended December 31, 2007, Energy Holdings had Net Income of $81 million, a decrease of $194 million as compared to the year ended December 31, 2006. Excluding Income from Discontinued Operations of $24 million and $299 million for the years ended December 31, 2007 and 2006, respectively, Income from Continuing Operations for the year ended December 31, 2007 was $57 million, an increase of $81 million as compared to 2006. The primary reason for the increase was the absence of the $178 million after-tax loss on the sale of RGE in 2006 which was partially offset by the after-tax loss of $23 million resulting from the sale of Chilquinta and Luz Del Sur in December 2007. The increase was also offset by lower operational earnings at PSEG Texas driven by lower generation at the plants and lower mark-to-market earnings which were $16 million, after-tax, in 2007 as compared to $29 million, after-tax, in 2006, due to increased future spark spreads caused by strengthening of forward curves for 2008 and beyond; lower operational earnings at Bioenergie in Italy largely due to sequestration and shut-down in early 2007; losses recorded on the early retirement of debt in December 2007; and lower leveraged lease income at Resources.

For the year ended December 31, 2006, Energy Holdings had Net Income of $275 million, an increase of $61 million as compared to the year ended December 31, 2005. Excluding Income from Discontinued Operations of $299 million and $67 million for the years ended December 31, 2006 and 2005, respectively, the Loss from Continuing Operations was $24 million for the year ended December 31, 2006, a decrease in earnings of $174 million as compared to 2005. The primary reason for the decline was the $178 million after-tax loss on the sale of RGE. The decreases were also due to the absence of an after-tax gain of $43 million from the sale of Resources leveraged lease investment in Generation Station Unit 2 (Seminole) in December 2005. The decreases were partially offset by strong operations at PSEG Texas combined with $29 million of after-tax mark-to-market gains on forward gas contracts in 2006 as compared to $3 million of after-tax MTM losses in 2005 at PSEG Texas.

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

For the Years Ended December 31,

2007 vs 2006

2006 vs 2005

2007

2006

2005

Increase (Decrease)

%

Increase (Decrease)

%

(Millions)

(Millions)

(Millions)

Operating Revenues

$

968

$

955

$

987

$

13

1

$

(32

)

(3

)

Energy Costs

$

450

$

523

$

517

$

(73

)

(14

)

$

$

6

1

Operation and Maintenance

$

139

$

132

$

157

$

7

5

$

(25

)

(16

)

Write-Down of Assets

$

16

$

274

$

$

(258

)

(94

)

$

274

N/A

Depreciation and Amortization

$

38

$

32

$

29

$

6

19

$

3

10

Income from Equity Method Investments

$

116

$

120

$

124

$

(4

)

(3

)

$

(4

)

(3

)

Other (Deductions) and Income

$

(26

)

$

15

$

(4

)

$

(41

)

N/A

$

19

N/A

Interest Expense

$

(153

)

$

(185

)

$

(195

)

$

(32

)

(17

)

$

(10

)

(5

)

Income Tax (Expense) Benefit

$

(207

)

$

33

$

(58

)

$

240

N/A

$

(91

)

N/A

Income from Discontinued Operations, including Gain on Disposal

$

24

$

299

$

67

$

(275

)

(92

)

$

232

N/A

The classification of the results of Global s investments is dependent upon Global s ownership percentage in the underlying investment which determines whether the investment is consolidated or if it is accounted for under the equity method of accounting. Global owns 100% of PSEG Texas and 85% of Bioenergie. As a result, the revenues, expenses, assets and liabilities of those investments are consolidated. Global s investments in Chilquinta and Luz del Sur, which were sold in December 2007, as well as its investments GWF Energy LLC (GWF), Kalaeloa Partners L.P. (Kalaeloa) and several other smaller investments are accounted for under the equity method of accounting. Therefore, Global s share of the net income from these projects is recorded as Income from Equity Method Investments on the Consolidated Statements of Operations. The results for SAESA and Electroandes are included in Discontinued Operations for all periods presented.

Operating Revenues

The increase of $13 million for the year ended December 31, 2007, as compared to 2006, was due to higher revenue at Global of $30 million. The increase at Global was primarily due to a pretax gain recorded on the sale of Chilquinta and Luz del Sur of $146 million that was largely offset by a reduction in generation revenues at PSEG Texas of $114 million. This decrease at PSEG Texas was largely due to reduced electricity sales of $80 million, coupled with lower MTM gains on electricity of $42 million, which were partially offset by a slight price increase in 2007 which generated an increase of $8 million. PSEG Texas had lower generation primarily due to cooler spring and summer weather in 2007 and also due to forced outages at the Odessa and Guadalupe facilities. The lower MTM gains were largely driven by strengthening of forward curves for 2008. The increases at Global were partially offset by lower revenues at Resources of $17 million primarily due to the effect on leverage leases from the adoption of FIN 48 and FSP13-2.

The decrease of $32 million for the year ended December 31, 2006, as compared to 2005, was due to lower revenues at Resources of $73 million primarily due to the absence of a $71 million pre-tax gain from the sale of Resources interest in Seminole Generation in December 2005 coupled with the absence of $20 million of leveraged lease income in 2006 due to the Seminole sale, partially offset by a $21 million write-off of a leveraged lease investment with United Airlines in 2005. The decrease at Resources was partially offset by higher revenues at Global of $41 million, which was primarily related to a $79 million increase at PSEG Texas due to higher unrealized gains on forward contracts which were slightly offset by a reduction in gas sales and a $24 million increase due to the consolidation of Bioenergie. These increases were partly offset by a $37 million decrease due to the absence of a gain from withdrawal from the Eagle Point Cogeneration Partnership in the prior year and the absence of $20 million of revenue due to the deconsolidation of Dhofar Power Company S.A.O.C.

Energy Costs

The decrease of $73 million for the year ended December 31, 2007, as compared to 2006, was primarily due to lower consumption driven by lower generation at PSEG Texas, including $42 million for lower fuel consumption, $22 million in reduced MTM costs on gas purchases driven by improvement of future spark spreads for 2008 and beyond and an $8 million reduction in purchased power costs.

The increase of $6 million for the year ended December 31, 2006, as compared to 2005, was primarily due to an $8 million increase due to the consolidation of Bioenergie in May 2006, partially offset by a $5 million decrease related to the deconsolidation of Dhofar Power.

Operation and Maintenance

The increase of $7 million for the year ended December 31, 2007, as compared to 2006, was primarily due to an increase of $12 million at Global driven largely by higher legal expenses of $4 million at Bioenergie (mainly in the early part of 2007 for resolution of legal issues); selling expenses of $6 million for the sale of equity method investments; and $5 million higher outage expenses at PSEG Texas. Global s increase was partially offset by decreases in general and administrative expenses at Resources and Energy Holdings (parent).

The decrease of $25 million for the year ended December 31, 2006, as compared to 2005, was primarily due to a reduction of $9 million at Resources, mainly due to a reduction of operating lease expense and a $10 million reduction at Global, primarily due to a $9 million decrease at PSEG Texas. Also contributing to the decrease was a $4 million reduction in administrative expenses related to lower corporate assessments, wages and benefits, and legal and consulting expense.

Write-Down of Assets

The $16 million write-down of assets in 2007 was primarily related to an additional $12 million pre-tax impairment recorded on Global s generation projects in Venezuela based on Global s estimated market valuation of these investments. Global also recorded an impairment loss of $4 million pre-tax on its investment in PPN primarily related to Global s estimated market valuation of that project.

The $274 million write-down of assets in 2006 was primarily related to a $263 million pre-tax loss on Global s sale of its 32% indirect ownership interest in RGE, $4 million pre-tax loss related to the sale of Global s interest in Magellan Capital Holdings Corporation, and a $7 million pre-tax loss on the impairment of Global s generation projects in Venezuela. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments.

Depreciation and Amortization

The increase of $6 million for the year ended December 31, 2007, as compared to 2006, was primarily due to the consolidation of Bioenergie in May 2006.

The increase of $3 million for the year ended December 31, 2006, as compared to 2005, was primarily due to a $3 million increase at Resources and a $4 million increase related to the consolidation of Bioenergie offset by a $4 million decrease resulting from the deconsolidation of Dhofar Power.

Income from Equity Method Investments

The decrease of $4 million for the year ended December 31, 2007, as compared to 2006, was primarily driven by the earnings of $11 million due to asset sales of RGE and Salalah in 2006; lower earnings of $8 million caused by lower generation and partial shutdown in 2007 at Bioenergie s equity investment and the consolidation of Bioenergie from mid-2006; reduction in the income from Bridgewater for $3 million, mainly due to the expiration of the Purchase Power Agreement (PPA) in August 2007; these were partially offset by higher earnings at Chilquinta, LDS, GWF, Kalaeloa for a total of $17 million.

The decrease of $4 million for the year ended December 31, 2006, as compared to 2005, was primarily driven by the absence of $12 million of earnings due to the sale of RGE in 2006 partially offset by the absence of foreign currency losses in 2005 from Bioenergie of $8 million.

Other Income and Deductions

The decrease of $41 million for the year ended December 31, 2007, as compared to 2006, was primarily due to a $35 million loss on the early retirement of debt resulting from the call for early redemption in December 2007 of Energy Holdings 10% Senior Notes due 2009; lower interest income from PSEG of $9 million due to lower average intercompany debt balances and increase of $5 million in the fair value loss on the Chilquinta swap at Global. These were partially offset by the income recorded for the settlement of the Konya Ilgin litigation of $9 million.

The increase of $19 million for the year ended December 31, 2006, as compared to 2005, was primarily due to an increase in interest and dividend income of $10 million and lower losses in foreign currency transactions due to favorable currency fluctuations mainly for Bioenergie operations in Italy.

Interest Expense

The decrease of $32 million for the year ended December 31, 2007, as compared to 2006, was mainly due to lower interest expense of $22 million on senior notes at Energy Holdings due to October 2006 and December 2007 redemptions, decrease in interest expense of $7 million due to Resources lower debt balance and the reversal of the accrued interest for the IRS audits for the years 1994 to 1996 and lower interest expense of $4 million at Global due to lower debt balance.

The decrease of $10 million for the year ended December 31, 2006, as compared to 2005, was mainly due to a decrease in Energy Holdings debt outstanding and a net decrease of $2 million resulting from the consolidation of Bioenergie and the deconsolidation of Dhofar Power.

Income Tax Expense

The increase of $240 million for the year ended December 31, 2007, as compared to 2006, was primarily attributable to $163 million of taxes recorded as a result of Global s sale of Chilquinta and Luz del Sur; $21 million of tax expense resulting from the implementation of FIN 48 at Global; higher taxation at Resources of $16 million due to higher pre-tax income and adjustment to FIN 48 tax reserves; and the absence of the $93 million tax benefit obtained in 2006 on the impairment of RGE. These were partially offset by the tax credit of $18 million in Energy Holdings due to early redemption of debt and $25 million lower taxes at Global due to lower pre-tax income in 2007 compared with 2006, excluding the amounts related to RGE, Chilquinta and Luz del Sur.

The decrease of $91 million for the year ended December 31, 2006, as compared to 2005, was primarily attributable to a tax benefit resulting from Global s sale of its 32% indirect ownership interest in RGE.

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

Electroandes

On October 17, 2007 Global completed the sale of Electroandes for a total purchase price of $390 million including the assumption of approximately $108 million of debt. Income from Discontinued Operations, including Gain on Disposal, related to Electroandes for the years ended December 31, 2007, 2006 and 2005 was $58 million, $16 million and $14 million respectively. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments for additional information.

SAESA Group

On December 18, 2007, Global announced that it plans to sell its investment in the SAESA group of companies. As a result, operating results for the SAESA Group have been presented as Discontinued Operations. As a result of its intention to sell the SAESA Group, Global recorded an $82 million income tax expense in the fourth quarter of 2007 related to the discontinuation of applying Accounting Principles Board (APB) Opinion No. 23, Accounting for Income Taxes Special Areas as the income generated by the SAESA Group is no longer expected to be indefinitely reinvested. (Loss) Income from Discontinued Operations related to the SAESA Group for the years ended December 31, 2007, 2006 and 2005 was $(34) million, $57 million and $35 million, respectively. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments for additional information.

Elcho and Skawina

In 2006, Global sold its interest in Elcho and Skawina, two coal-fired plants in Poland. Proceeds, net of transaction costs, were $476 million. Income from Discontinued Operations, including the Gain on Disposal, related to Elcho and Skawina for the years ended December 31, 2006 and 2005 was $226 million and $18 million, respectively. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments for additional information.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of liquidity and capital resources is on a consolidated basis for PSEG, noting the uses and contributions, where material, of PSEG s three direct operating subsidiaries, Power, PSE&G and Energy Holdings.

Financing Methodology

PSEG, Power and PSE&G

Capital requirements for Power and PSE&G are met through liquidity provided by internally generated cash flow and external financings. PSEG and Power from time to time make equity contributions or otherwise provide credit support to their respective direct and indirect subsidiaries to provide for part of their capital and cash requirements, generally relating to long-term investments.

At times, PSEG utilizes intercompany dividends and intercompany loans (except however, that Fossil, Nuclear and ER&T may not, without prior FERC approval, and PSE&G may not, without prior BPU approval, make loans to their affiliates) to satisfy various subsidiary or parental needs and efficiently manage short-term cash. Any excess funds are invested in short-term liquid investments.

External funding to meet PSEG s, Power s and PSE&G s needs consist of corporate finance transactions. The debt incurred is the direct obligation of those respective entities. Some of the proceeds of these debt transactions may be used by the respective obligor to make equity investments in its subsidiaries.

As discussed below, depending on the particular company, external financing may consist of public and private capital market debt and equity transactions, bank revolving credit and term loans, commercial paper and/or project financings. Some of these transactions involve special purpose entities (SPEs), formed in accordance with applicable tax and legal requirements in order to achieve specified financial advantages, such as favorable legal liability treatment. PSEG consolidates SPEs, as applicable, in accordance with FIN No. 46, Consolidation of Variable Interest Entities (VIEs) (FIN 46).

The availability and cost of external capital is affected by each entity s performance, as well as by the performance of their respective subsidiaries and affiliates. This could include the degree of structural separation between PSEG and its subsidiaries and the potential impact of affiliate ratings on consolidated and unconsolidated credit quality. Additionally, compliance with applicable financial covenants will depend upon future financial position, earnings and net cash flows, as to which no assurances can be given.

Over the next several years, PSEG, Power and PSE&G may be required to extinguish or refinance maturing debt and, to the extent there is not sufficient internally generated funds, may incur additional debt and/or provide equity to fund investment activities. Any inability to obtain required additional external capital or to extend or replace maturing debt and/or existing agreements at current levels and reasonable interest rates may adversely affect PSEG s, Power s and PSE&G s respective financial condition, results of operations and net cash flows.

From time to time, PSEG, Power and PSE&G may repurchase portions of their respective debt securities using funds from operations, asset sales, commercial paper, debt issuances, equity issuances and other sources of funding and may make exchanges of new securities, including common stock, for outstanding securities. Such repurchases may be at variable prices below, at or above prevailing market prices and may be conducted by way of privately negotiated transactions, open-market purchases, tender or exchange offers or other means. PSEG, Power and PSE&G may utilize brokers or dealers or effect such repurchases directly. Any such repurchases may be commenced or discontinued at any time without notice.

Operating Cash Flows-

PSEG, Power and PSE&G

PSEG expects strong cash from operations primarily driven by earnings from Power due to improvements in energy margins and capacity markets. The strong operating cash flows combined with proceeds from potential asset sales and financing activities are expected to be sufficient to fund capital expenditures and shareholder dividend payments, with excess cash available to invest in the business, reduce debt and/or repurchase common stock.

PSEG

For the year ended December 31, 2007, PSEG s operating cash flow decreased by $13 million as compared to 2006. For the year ended December 31, 2006, PSEG s operating cash flow increased by $982 million as compared to 2005. The net changes were due to net changes from its subsidiaries as discussed below.

Power

Power s operating cash flow increased $162 million for the year ended December 31, 2007 as compared to 2006, due principally to an increase in net income of $457 million, net of the Loss on Disposal of Lawrenceburg, partially offset by an increase of $321 million in margin receivables related to higher collateral requirements.

Power s operating cash flow increased $907 million for the year ended December 31, 2006, as compared to 2005, due to a significant reduction in margin requirements and fuel inventories, largely resulting from decreases in commodity prices.

PSE&G

PSE&G s operating cash flow decreased $128 million for the year ended December 31, 2007 as compared to 2006 primarily due to a decline in cash from working capital. The operating cash flow for the year 2006 was $806 million primarily due to very cold weather at the end of 2005 which resulted in increased cash flow during 2006. The return of more normal weather conditions in 2007 caused operating cash flow to decline to the 2005 level.

PSE&G s operating cash flow increased $122 million for the year ended December 31, 2006 as compared to 2005, primarily due to an increase in working capital. The colder than normal winter in 2005 caused an increase in cash flow in 2006.

Energy Holdings

Energy Holdings operating cash flow decreased $91 million for the year ended December 31, 2007, as compared to 2006. The decrease was mainly due to a $100 million tax deposit made with the IRS in the fourth quarter of 2007 and the timing of tax payments related to Global s sales of Elcho, Skawina and RGE in 2006.

Energy Holdings operating cash flow decreased $98 million for the year ended December 31, 2006 as compared to 2005. The decrease was mainly due to taxes paid related to the sale of Elcho, Skawina and RGE in 2006. The proceeds from these sales are included in Cash Flows from Investing Activities on PSEG s Consolidated Statements of Cash Flows.

Common Stock Dividends

On January 15, 2008, PSEG s Board of Directors approved a two-for-one stock split of the PSEG s outstanding shares of common stock. All share and per share amounts included in this Form 10-K retroactively reflect the effect of the stock split. Dividend payments on common stock for the year ended December 31, 2007 were $1.17 per share and totaled $594 million. Dividend payments on common stock for the year ended December 31, 2006 were $1.14 per share and totaled $574 million.

On January 15, 2008, PSEG s Board of Directors also approved a $0.03 increase in its quarterly common stock dividend, from $0.2925 to $0.3225 per share for the first quarter of 2008. This reflects an indicated annual dividend rate of $1.29 per share. PSEG expects to continue to pay cash dividends on its common stock, however, the declaration and payment of future dividends to holders of PSEG common stock will be at the discretion of the Board of Directors and will depend upon many factors, including PSEG s financial condition, earnings, capital requirements of its business, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Short-Term Liquidity

As of December 31, 2007, PSEG, Power and PSE&G had the following committed credit facilities Each of the facilities is restricted as to availability and use to the specific companies as listed below. PSEG, Power and PSE&G believe sufficient liquidity exists to fund their respective short-term cash requirements.

Company

Expiration Date

Total Facility

Primary Purpose

Usage as of December 31, 2007

Available Liquidity as of December 31, 2007

(Millions)

PSEG:

5-year Credit Facility(A)

Dec 2012

$

1,000

CP Support/Funding/

$

1

(B)

$

999

Letters of Credit

Uncommitted Bilateral Agreement

N/A

N/A

Funding

$

$

N/A

Power:

5-year Credit Facility(A)

Dec 2012

$

1,600

Funding/Letters of

$

140

(B)

$

1,460

Credit

Bilateral Credit Facility

March 2010

$

100

Funding/Letters of

$

56

(B)

$

44

Credit

Bilateral Credit Facility

March 2008

$

200

Funding/Letters of

$

28

(B)

$

172

Credit

PSE&G:

5-year Credit Facility(A)

June 2012

$

600

CP Support/Funding/

$

55

$

545

Letters of Credit

Uncommitted Bilateral Agreement

N/A

N/A

Funding

$

10

N/A

(A)

In 2012, facilities reduce by $47 million, $75 million, and $28 million for PSEG, Power and PSE&G, respectively.

(B)

These amounts relate to letters of credit outstanding.

Power

As of December 31, 2007, Power had borrowed $238 million from PSEG in the form of an intercompany loan.

On June 25, 2007, Power refinanced the $200 million PSEG/Power joint and several co-borrower bilateral credit facility. The maturity was extended to March 2008 and terms were modified so that Power is the sole borrower under this facility.

Power s required margin postings for sales contracts entered into in the normal course of business will fluctuate based on volatility in commodity prices. Should commodity prices rise, additional margin calls may be necessary relative to existing power sales contracts. As Power s contract obligations are fulfilled, liquidity requirements are reduced.

In addition, ER&T maintains agreements that require Power, as its guarantor under performance guarantees, to satisfy certain creditworthiness standards. In the event of a deterioration of Power s credit rating to below investment grade, which represents at least a two level downgrade from its current ratings, many of these agreements allow the counterparty to demand that ER&T provide performance assurance, generally in the form of a letter of credit or cash. Providing this support would increase Power s costs of doing business and could restrict the ability of ER&T to manage and optimize Power s asset portfolio. Power believes it has sufficient liquidity to meet any required posting of collateral likely to result from a credit rating downgrade. See Note 12. Commitments and Contingent Liabilities for further information.

External Financings

PSEG

For the year ended December 31, 2007, PSEG issued 2,154,244 shares of its common stock in connection with settling stock options under its Long-Term Incentive Plan (LTIP) for $48 million.

For the year ended December 31, 2007, PSEG issued 811,780 shares of its common stock under its Dividend Reinvestment and Stock Purchase Plan (DRASPP) and Employee Stock Purchase Plan (ESPP) for $35 million.

In December 2007, PSEG called for redemption of $186 million of its Subordinated Debentures underlying $180 million of PSEG Funding Trust II, Trust Preferred Securities due 2032 at 100% of the principal amount. They were redeemed in December 2007.

In November 2007, PSEG redeemed $474 million of its Subordinated Debentures underlying $460 million of PSEG Funding Trust I, Participating Equity Preferred Securities.

In October 2007, PSEG repaid $49 million of its 6.89% Senior Notes which are due in equal annual installment payments through 2009.

In May 2007, PSEG called for redemption of the outstanding $375 million of its Floating Rate Senior Notes Due 2008 at 100% of the principal amount.

Power

In December 2007, Power issued $44 million of 4.00% Pollution Control Bonds due 2042 in connection with a project being completed at one of its generation facilities in Pennsylvania.

In November 2007, Power issued $40 million of 5.75% Pollution Control Bonds due 2037 in connection with a project being completed at one of its generation facilities in Connecticut.

During 2007, Power paid cash dividends to PSEG totaling $1.075 billion.

PSE&G

PSE&G has $494 million of variable rate pollution control notes outstanding which service and secure a like amount of insured tax-exempt variable rate bonds of the Pollution Control Authority of Salem County.

In February 2008, PSE&G purchased $105 million of the Salem County Authority bonds which were being held by the broker/dealer. PSE&G has elected to change the interest rate mode on the bonds to a weekly rate. PSE&G intends to acquire all of these bonds by April 2008 upon the change of interest rate modes and to hold them until they can be remarketed or refinanced, possibly later in 2008.

In May 2007, PSE&G issued $350 million of 5.80% Secured Medium-Term Series E Notes due 2037. The proceeds were used to reduce short-term debt.

In January 2007, PSE&G repaid at maturity $113 million of its 6.25% Series WW First and Refunding Mortgage Bonds.

During 2007, PSE&G Transition Funding LLC (Transition Funding) repaid $161 million of its transition bonds and PSE&G Transition Funding II LLC (Transition Funding II) repaid $9 million of its transition bonds.

PSE&G paid cash dividends to PSEG of $200 million in 2007.

Energy Holdings

In December 2007, Energy Holdings called for redemption all of the outstanding $400 million of 10% Senior Notes due 2009 which were redeemed in January 2008. In addition, in December 2007, Energy Holdings repurchased $14 million of the remaining $544 million of the 8.50% Senior Notes due 2011.

In August 2007, SAESA, a wholly owned subsidiary of Global, issued 3.80% bonds (approximately 7% , including current inflationary adjustment) for net proceeds of $163 million with a final maturity of June 30, 2028. The proceeds were used principally to repay loans due to Energy Holdings which then loaned the funds to PSEG for short-term funding.

During 2007, Energy Holdings made cash distributions to PSEG of $355 million in the form of returns of capital.

During 2007, Energy Holdings subsidiaries repaid $57 million of non-recourse debt, including $51 million by Global, of which $45 million related to the PSEG Texas facilities and $6 million to the SAESA Group, $4 million by Resources and $2 million by EGDC.

Debt Covenants

PSEG, Power and PSE&G

PSEG s, Power s and PSE&G s respective credit agreements may contain maximum debt to equity ratios, minimum cash flow tests and other restrictive covenants and conditions to borrowing. Compliance with applicable financial covenants will depend upon the respective future financial position, level of earnings and cash flows of PSEG, Power and PSE&G, as to which no assurances can be given. The ratios presented below are for the benefit of the investors of the related securities to which the covenants apply. They are not intended as financial performance or liquidity measures. The debt underlying the preferred securities of PSEG, which is presented in Long-Term Debt in accordance with FIN 46, is not included as debt when calculating these ratios, as provided for in the various credit agreements.

PSEG

Financial covenants contained in PSEG s note purchase agreements related to the private placement of debt include a ratio of total debt (excluding non-recourse project financings, securitization debt and debt underlying preferred securities and including commercial paper and loans and certain letters of credit) to total capitalization (including preferred securities outstanding) covenant. This covenant requires that such ratio not be more than 70.0%. As of December 31, 2007, PSEG s ratio of debt to capitalization (as defined above) was 51.9%.

PSEG s credit facility contains a similar but less restrictive financial covenant where total debt excludes letters of credit related to collateral postings and total capitalization excludes any impacts for Accumulated Other Comprehensive Income/Loss adjustments related to marking energy contracts to market and equity reductions from the funded status of pensions or benefit plans associated with Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans . This covenant requires that such ratio not be more than 70.0%. As of December 31, 2007, PSEG s ratio of debt to capitalization (as defined above) was 49.9%.

Power

Financial covenants contained in Power s credit facility include a ratio of debt to total capitalization covenant. The Power ratio is the same debt to total capitalization calculation as set forth above for PSEG except common equity is adjusted for the $986 million Basis Adjustment (see Consolidated Balance Sheets). This covenant requires that such ratio will not exceed 65.0%. As of December 31, 2007, Power s ratio of debt to total capitalization (as defined above) was 41.3%.

PSE&G

Financial covenants contained in PSE&G s credit facilities include a ratio of long-term debt (excluding securitization debt, long-term debt maturing within one year and short-term debt) to total capitalization covenant. This covenant requires that such ratio will not be more than 65.0%. As of December 31, 2007, PSE&G s ratio of long-term debt to total capitalization (as defined above) was 48.0%.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2007, PSE&G s Mortgage coverage ratio was 4.6 to 1 and the Mortgage would permit up to approximately $2.1 billion aggregate principal amount of new Mortgage Bonds to be issued against previous bondable additions and improvements to its property.

Cross Default Provisions

PSEG, Power and PSE&G

The PSEG bank credit agreement contains default provisions under which a default by it in an aggregate amount of $50 million or greater would result in the potential acceleration of payment under this agreement. Under certain conditions, a default by Power or PSE&G in an aggregate amount of $50 million or greater would also result in potential acceleration of payment under this agreement. PSEG, Power and PSE&G have removed Energy Holdings from all cross default provisions.

PSEG s bank credit agreement and note purchase agreements related to private placement of debt (collectively, Credit Agreements) contain cross default provisions under which certain payment defaults by Power or PSE&G, certain bankruptcy events relating to Power or PSE&G, the failure by Power or PSE&G to satisfy certain final judgments or the occurrence of certain events of default under the financing agreements of Power or PSE&G, would each constitute an event of default under the PSEG Credit Agreements. Under the note purchase agreements, it is also an event of default if Power or PSE&G ceases to be wholly-owned by PSEG. Under the bank credit agreement, both Power and PSE&G would have to cease to be wholly-owned by PSEG before an event of default would occur.

Power

The Power Senior Debt Indenture contains a default provision under which a default by Power, Nuclear, Fossil or ER&T in an aggregate amount of $50 million or greater would result in an event of default and the potential acceleration of payment under the indenture. There are no cross defaults within Power s indenture from PSEG, Energy Holdings or PSE&G.

The Power credit agreement also has a provision under which a default by Power, Nuclear, Fossil or ER&T in an aggregate amount of $50 million or greater would result in an event of default and the potential acceleration of payment under that agreement.

PSE&G

PSE&G s Mortgage has no cross defaults. The PSE&G Medium-Term Note Indenture has a cross default to the PSE&G Mortgage. The PSE&G credit agreement has a provision under which a default by PSE&G in the aggregate of $50 million or greater would result in an event of default and the potential acceleration of payment under that agreement.

Ratings Triggers

PSEG, Power and PSE&G

The debt indentures and credit agreements of PSEG, PSE&G, Power and Energy Holdings do not contain any material ratings triggers that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements.

Power

In connection with the management and optimization of Power s asset portfolio, ER&T maintains underlying agreements that require Power, as its guarantor under performance guarantees, to satisfy certain creditworthiness standards. In the event of a deterioration of Power s credit rating to below an investment grade rating, many of these agreements allow the counterparty to demand that ER&T provide performance assurance, generally in the form of a letter of credit or cash. As of December 31, 2007, if Power were to lose its investment grade rating and assuming all the counterparties to agreements in which ER&T is out-of-the-money were contractually entitled to demand, and demanded, performance assurance, ER&T could be required to post collateral in an amount equal to approximately $777 million. See Note 12. Commitments and Contingent Liabilities.

PSE&G

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

PSE&G is the servicer for the bonds issued by Transition Funding and Transition Funding II. If PSE&G were to lose its investment grade rating, PSE&G would be required to remit collected cash daily to the bond trustee. Currently, cash is remitted monthly.

Credit Ratings

PSEG, Power and PSE&G

PSE&G has $494 million of variable-rate pollution control notes outstanding which service and secure a like amount of insured tax-exempt variable-rate bonds of the Pollution Control Authority of Salem County. The credit ratings of these tax-exempt securities are linked to the credit ratings of the insurers. In December 2007, due to credit pressures experienced by the insurers, the credit ratings on these tax-exempt securities were placed on review for possible downgrade by Moody s and negative (Neg) outlook by S&P. In January 2008, Fitch downgraded these securities from AAA to A. In early February 2008, Moody s downgraded these securities from Aaa to A3. Currently, PSE&G is exposed to interest rate risk with resets every 35 days on the Salem Authority bonds and, in turn, PSE&G s variable-rate pollution control bonds.

On November 20, 2007, Fitch upgraded the senior unsecured debt rating of PSEG and Power to BBB+ from BBB and the rating outlook for each entity is now stable.

On June 22, 2007, S&P revised its outlook for the credit ratings of each of PSEG, Power and PSE&G from Neg to stable and upgraded its rating for the commercial paper of PSEG and PSE&G from A3 to A2.

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

Moody s(A)

S&P(B)

Fitch(C)

PSEG:

Outlook

Neg

Stable

Stable

Commercial Paper

P2

A2

F2

Power:

Outlook

Stable

Stable

Stable

Senior Notes

Baa1

BBB

BBB+

PSE&G:

Outlook

Neg

Stable

Stable

Mortgage Bonds

A3

A

A

Preferred Securities

Baa3

BB+

BBB+

Commercial Paper

P2

A2

F2

(A)

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

(B)

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

(C)

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

Other Comprehensive Income

PSEG, Power and PSE&G

For the year ended December 31, 2007, PSEG, Power and PSE&G had Other Comprehensive (Losses) Income of $(32) million, $(115) million and $1 million, respectively, due to higher unrealized losses on derivative contracts accounted for as hedges at Power, partially offset by gains from foreign currency translation adjustments.

CAPITAL REQUIREMENTS

PSEG, Power and PSE&G

It is expected that the majority of each subsidiary s capital requirements over the next five years will come from internally generated funds. Projected construction and investment expenditures, excluding nuclear fuel purchases, for PSEG s subsidiaries for the next five years are presented in the table below. These amounts are subject to change, based on various factors.

2008

2009

2010

2011

2012

(Millions)

Power:

Hudson Environmental

$

240

$

300

$

215

$

5

$

Mercer Environmental

215

100

10

Other Environmental

140

40

15

20

25

Exploration of New Nuclear Plant

5

20

15

15

55

Other Growth Opportunities

5

60

175

200

80

Other

285

155

190

190

190

Total Power

890

675

620

430

350

2008

2009

2010

2011

2012

(Millions)

PSE&G:

Transmission

System Reinforcement

140

160

265

420

465

Facility Replacement

15

30

30

30

30

Environmental/Regulatory

5

Distribution

Support Facilities

175

175

275

235

220

New Business

165

160

160

165

175

Reliability Enhancements

110

120

95

90

90

Facility Replacement

165

180

190

190

200

Environmental/Regulatory

70

80

80

85

85

Total PSE&G

840

905

1,100

1,215

1,265

Other

65

35

30

30

30

Total PSEG

$

1,795

$

1,615

$

1,750

$

1,675

$

1,645

Power

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

Hudson Environmental construction of pollution control equipment, including a selective catalytic reduction system, a scrubber, a baghouse and a carbon injection system at our Hudson facility.

Mercer Environmental construction of pollution control equipment, including scrubbers and baghouses, at our Mercer facility.

Other Environmental construction of other pollution control equipment, including scrubbers at our Keystone facility.

Exploration of New Nuclear Plant costs associated with exploring the feasibility of, and the technologies involved with, building a new nuclear plant.

Other Growth Opportunities costs associated with potential opportunities to build other new plants such as peaking facilities.

Other various capital projects at existing facilities to either extend plants useful lives or increase operating output.

In 2007, Power made approximately $562 million of capital expenditures (excluding $153 million for nuclear fuel), primarily related to various projects at Fossil and Nuclear.

PSE&G

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

Support Facilities ancillary equipment needed to support the business lines, such as computers, office furniture, and buildings and structures housing support personnel or equipment/inventory.

New Business investments made in support of new business to PSE&G (e.g. add new customers).

Reliability Enhancements investments made to improve the reliability and efficiency of the system or function.

Facility Replacement investments made to replace systems or equipment in kind.

Environmental/Regulatory investments made in response to regulatory or legal mandates where financial loss is imminent if not pursued.

In 2007, PSE&G made approximately $570 million of capital expenditures, primarily for reliability of transmission and distribution systems. The $570 million does not include approximately $37 million spent on cost of removal.

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

The following table reflects PSEG s and its subsidiaries contractual cash obligations and other commercial commitments in the respective periods in which they are due. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. The table also does not reflect debt maturities of Energy Holdings non-consolidated investments. If those obligations were not able to be refinanced by the project, Energy Holdings may elect to make additional contributions in these investments. For additional information, see Note 10. Schedule of Consolidated Debt. In addition, the table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities under FIN 48 since PSEG is unable to reasonably estimate the timing of FIN 48 liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Note 15. Income Taxes for additional information.

Contractual Cash Obligations

**Total
Amount
Committed**

**Less
Than
1 year**

**2 3
years**

**4 5
years**

**Over
5 years**

(Millions)

Short-Term Debt Maturities

PSEG

PSE&G

$

65

$

65

$

$

$

Long-Term Recourse Debt Maturities

PSEG

298

49

249

Power

2,902

250

1,466

1,186

PSE&G

3,352

250

60

300

2,742

Transition Funding (PSE&G)

1,623

169

364

399

691

Transition Funding II (PSE&G)

86

10

21

22

33

Energy Holdings

1,137

607

530

Long-Term Non-Recourse Project Financing

Energy Holdings

386

37

328

7

14

Interest on Recourse Debt

PSEG

34

21

13

Power

1,853

195

378

257

1,023

PSE&G

2,459

180

334

333

1,612

Transition Funding (PSE&G)

481

103

174

124

80

Transition Funding II (PSE&G)

16

4

6

4

2

Energy Holdings

180

67

90

23

Interest on Non-Recourse Project Financing

Energy Holdings

58

27

27

2

2

Capital Lease Obligations

PSEG

55

7

14

14

20

Power

15

2

4

9

Energy Holdings

47

13

23

5

6

Operating Leases

PSE&G

11

3

6

1

1

Energy Holdings

3

1

2

Energy-Related Purchase Commitments

Power

3,374

791

1,436

624

523

Energy Holdings

106

106

Total Contractual Cash Obligations

$

18,541

$

2,707

$

3,779

$

4,111

$

7,944

Commercial Commitments

Standby Letters of Credit

Power

$

225

$

225

$

$

$

Energy Holdings

18

3

15

Guarantees and Equity Commitments

Energy Holdings

16

4

12

Total Commercial Commitments

$

259

$

232

$

27

$

$

Liability Payments Under Fin 48

PSE&G

$

3

$

3

$

$

$

Energy Holdings

39

39

See Note 12. Commitments and Contingent Liabilities for a discussion of contractual commitments for a variety of services for which annual amounts are not quantifiable.

OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy contracts. See Note 12. Commitments and Contingent Liabilities for further discussion.

Energy Holdings

Global has certain investments that are accounted for under the equity method in accordance with accounting principles generally accepted in the United States (GAAP). Accordingly, amounts recorded on the Consolidated Balance Sheets for such investments represent Global s equity investment, which is increased for Global s pro-rata share of earnings less any dividend distribution from such investments. The companies in which Global invests that are accounted for under the equity method have an aggregate $351 million of debt on their combined, consolidated financial statements. PSEG s pro-rata share of such debt is $173 million. This debt is non-recourse to PSEG, Energy Holdings and Global. PSEG is generally not required to support the debt service obligations of these companies. However, default with respect to this non-recourse debt could result in a loss of invested equity.

Resources has investments in leveraged leases that are accounted for in accordance with SFAS No. 13, Accounting for Leases. Leveraged lease investments generally 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 is not presented on Energy Holdings Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secure the loan. As a lessor, Resources has ownership rights to the property and rents the property to the lessees for use in their business operation. As of December 31, 2007, Resources equity investment in leased assets was approximately $781 million, net of deferred taxes of approximately $2 billion. For additional information, see Note 8. Long-Term Investments.

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

Energy Holdings has guaranteed certain obligations of its subsidiaries or affiliates related to certain projects. See Note 12. Commitments and Contingent Liabilities for additional information.

CRITICAL ACCOUNTING ESTIMATES

PSEG, Power and PSE&G

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have