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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PART III

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.

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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.

Regulation of Wholesale Sales Generation/Market Issues

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 a material impact on results of operations, financial position and cash flows. The managements of PSEG, Power and PSE&G have each determined that the following estimates are considered critical to the application of rules that relate to their respective businesses.

Accounting for Pensions

PSEG, Power and PSE&G account for pensions under SFAS No. 87, Employers Accounting for Pensions (SFAS 87). Pension costs under SFAS 87 are calculated using various economic and demographic assumptions. Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns. In 2007, PSEG and its subsidiaries recorded pension expense of $43 million, compared to $97 million in 2006 and $109 million in 2005. Additionally, in 2007, PSEG and its respective subsidiaries contributed cash of approximately $16 million, compared to cash contributions of $50 million in 2006 and $155 million in 2005.

PSEG s discount rate assumption, which is determined annually, is based on the rates of return on high-quality fixed-income investments currently available and expected to be available during the period to maturity of the pension benefits. The discount rate used to calculate pension obligations is determined as of December 31 each year, PSEG s SFAS 87 measurement date. The discount rate used to determine year-end obligations is also used to develop the following year s net periodic pension cost. The discount rates used in PSEG s 2006 and 2007 net periodic pension costs were 5.75% and 6.00%, respectively. PSEG s 2008 net periodic pension cost was developed using a discount rate of 6.50%.

PSEG s expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class and long-term inflation assumptions. For 2006 and 2007, PSEG assumed a rate of return of 8.75% on PSEG s pension plan assets. For 2008, PSEG will continue the rate of return assumption of 8.75%.

Based on the above assumptions, PSEG has estimated net period pension costs of approximately $37 million and contributions of up to approximately $50 million in 2008. As part of the business planning process, PSEG has modeled its future costs assuming an 8.75% rate of return and a 6.50% discount rate for 2009 and beyond. Actual future pension expense and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to PSEG s projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in PSEG s pension plans.

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

Assumption

2008
Assumptions

Change/
(Decrease)

As of
December 31, 2007
Impact on
Pension Benefit
Obligation

Increase to
Pension Expense
in 2008

(Millions)

Discount Rate

6.50

%

(1.00

%)

$

478

$

43

Rate of Return on Plan Assets

8.75

%

(1.00

%)

$

$

33

Accounting for Deferred Taxes

PSEG, Power and PSE&G provide for income taxes based on the liability method required by SFAS No. 109, Accounting for Income Taxes (SFAS 109). Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis, as well as net operating loss and credit carryforwards.

PSEG, Power and PSE&G evaluate the need for a valuation allowance against their respective deferred tax assets based on the likelihood of expected future taxable income. PSEG, Power and PSE&G do not believe a valuation allowance is necessary; however, if the expected level of future taxable income changes or certain tax planning strategies become unavailable, PSEG, Power and PSE&G would record a valuation allowance through income tax expense in the period the valuation allowance is deemed necessary. Resources and Global s ability to realize their deferred tax assets are dependent on PSEG s subsidiaries ability to generate ordinary income and capital gains.

Uncertain Tax Positions

PSEG, Power and PSE&G are required to make judgments regarding the potential tax effects of various financial transactions and results of operations in order to estimate their obligations to taxing authorities. Beginning January 1, 2007, PSEG, Power and PSE&G began accounting for uncertain income tax positions using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being ultimately realized upon ultimate settlement in accordance with FIN 48. If it is not more likely than not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Prior to January 1, 2007, PSEG, Power and PSE&G estimated their uncertain income tax obligations in accordance with SFAS No. 109, Accounting for Income Taxes (SFAS No. 109) and SFAS No. 5, Accounting for Contingencies (SFAS No. 5). The Registrants also have non-income tax obligations related to real estate, sales and use and employment-related taxes and ongoing appeals related to these tax matters that are outside the scope of FIN 48 and accounted for under SFAS No. 5.

Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. PSEG, Power and PSE&G also assess their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. PSEG, Power and PSE&G do not record valuation allowances for deferred tax assets related to capital losses that they believe will be realized in future periods. While PSEG, Power and PSE&G believe the resulting tax reserve balances as of December 31, 2007 are appropriately accounted for in accordance with FIN 48, SFAS No. 5 and SFAS No. 109, as applicable, the ultimate outcome of such matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material.

Hedge and MTM Accounting

SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133) requires an entity to recognize the fair value of derivative instruments held as assets or liabilities on the balance sheet. SFAS 133 applies to all derivative instruments held by PSEG, Power and PSE&G. The fair value of most derivative instruments is determined by reference to quoted market prices, listed contracts, or quotations from brokers. Some of these derivative contracts are long term and rely on forward price quotations over the entire duration of the derivative contracts.

In the absence of the pricing sources listed above, for a small number of contracts, PSEG and its subsidiary companies utilize mathematical models that rely on historical data to develop forward pricing information in the determination of fair value. Because the determination of fair value using such models is subject to significant assumptions and estimates, PSEG and its subsidiary companies developed reserve policies that are consistently applied to model-generated results to determine reasonable estimates of value to record in the financial statements.

PSEG and its subsidiaries have entered into various derivative instruments in order to hedge exposure to commodity price risk, interest rate risk and foreign currency risk. Many such instruments have been designated as cash flow hedges. For a cash flow hedge, the change in the value of a derivative instrument is measured against the offsetting change in the value of the underlying contract or business condition the derivative instrument is intended to hedge. This is known as the measure of derivative effectiveness. In accordance with SFAS 133, the effective portion of the change in the fair value of a derivative instrument designated as a cash flow hedge is reported in Accumulated Other Comprehensive Loss, net of tax, or as a Regulatory Asset (Liability). Amounts in Accumulated Other Comprehensive Loss are ultimately recognized in earnings when the related hedged forecasted transaction occurs. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Loss. The changes in the fair value of the ineffective portions of derivative instrument designated as cash flow hedges are recorded in earnings.

For Power s wholesale energy business, many of the forward sale, forward purchase and other option contracts are derivative instruments that hedge commodity price risk, but for which the businesses are not able to apply the hedge accounting guidance in SFAS 133. The changes in value of such derivative contracts are marked to market through earnings as commodity prices fluctuate. As a result, the earnings of PSEG and Power may experience significant fluctuations depending on the volatility of commodity prices.

For Power s energy trading activities, all changes in the fair value of energy trading derivative contracts are recorded in earnings.

For additional information regarding Derivative Financial Instruments, see Note 11. Financial Risk Management Activities.

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Power

Nuclear Decommissioning Trust (NDT) Funds

Power accounts for the assets in the NDT Funds under SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities (SFAS 115). The assets in the NDT Funds are classified as available-for-sale securities and are marked to market with unrealized gains and losses recorded in Accumulated Other Comprehensive Loss unless securities with such unrealized losses are deemed to be other-than-temporarily-impaired. Realized gains, losses and dividend and interest income are recorded on Power s and PSEG s Statements of Operations under Other Income and Other Deductions. Unrealized losses that are deemed to be other than temporarily impaired, as defined under SFAS 115, and related interpretive guidance, are charged against earnings rather than Accumulated Other Comprehensive Loss.

PSE&G

Unbilled Revenues

Electric and gas revenues are recorded based on services rendered to customers during each accounting period. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. Unbilled usage is calculated in two steps. The initial step is to apply a base usage per day to the number of unbilled days in the period. The second step estimates seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms. The resulting usage is priced at current rate levels and recorded as revenue. A calculation of the associated energy cost for the unbilled usage is recorded as well. Each month the prior month s unbilled amounts are reversed and the current month s amounts are accrued. Using benchmarks other than those used in this calculation could have a material effect on the amounts accrued in a reporting period. The resulting revenue and expense reflect the service rendered in the calendar month.

PSE&G

SFAS 71

PSE&G prepares its Consolidated Financial Statements in accordance with the provisions of SFAS 71, which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (a Regulatory Asset) or recognize obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs, which will be amortized over various future periods. To the extent that collection of such costs or payment of liabilities is no longer probable as a result of changes in regulation and/or PSE&G s competitive position, the associated Regulatory Asset or Liability is charged or credited to income. See Note 5. Regulatory Matters for additional information related to these and other regulatory issues.

ITEM 7A.

QUALITATIVE AND QUANTITATIVE DISCLOSURES ABOUT MARKET RISK

PSEG, Power and PSE&G

The market risk inherent in PSEG s, Power s and PSE&G s market-risk sensitive instruments and positions is the potential loss arising from adverse changes in foreign currency exchange rates, commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements (Notes). It is the policy of each entity to use derivatives to manage risk consistent with its respective business plans and prudent practices. PSEG, Power and PSE&G have a Risk Management Committee comprised of executive officers who utilize an independent risk oversight function to ensure compliance with corporate policies and prudent risk management practices.

Additionally, PSEG, Power and PSE&G are exposed to counterparty credit losses in the event of non-performance or non-payment. PSEG has a credit management process, which is used to assess, monitor and mitigate counterparty exposure for PSEG and its subsidiaries. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on PSEG and its subsidiaries financial condition, results of operations or net cash flows.

Commodity Contracts

PSEG and Power

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

Normal Operations and Hedging Activities

Power enters into physical contracts, as well as financial contracts, including forwards, futures, swaps and options designed to reduce risk associated with volatile commodity prices. Commodity price risk is associated with market price movements resulting from market generation demand, changes in fuel costs and various other factors.

Under SFAS 133, changes in the fair value of qualifying cash flow hedge transactions are recorded in Accumulated Other Comprehensive Loss, and gains and losses are recognized in earnings when the underlying transaction occurs. Changes in the fair value of derivative contracts that do not meet hedge criteria under SFAS 133 and the ineffective portion of hedge contracts are recognized in earnings currently. Additionally, changes in the fair value attributable to fair value hedges are similarly recognized in earnings.

Many non-trading contracts qualify for the normal purchases and normal sales exemption under SFAS 133 and are accounted for upon settlement.

Trading

Power maintains a strategy of entering into positions to optimize the value of its portfolio of generation assets, gas supply contracts and its electric and gas supply obligations. Power engages in physical and financial transactions in the electricity wholesale markets and executes an overall risk management strategy to mitigate the effects of adverse movements in the fuel and electricity markets. In addition, Power has non-asset based trading activities, which have significantly decreased. These contracts also involve financial transactions including swaps, options and futures. These activities are marked to market in accordance with SFAS 133 with gains and losses recognized in earnings.

Value-at-Risk (VaR) Models

Power

Power uses VaR models to assess the market risk of its commodity businesses. The portfolio VaR model for Power includes its owned generation and physical contracts, as well as fixed price sales requirements, load requirements and financial derivative instruments. VaR represents the potential gains or losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. Power estimates VaR across its commodity businesses.

Power manages its exposure at the portfolio level. Its portfolio consists of owned generation, load-serving contracts (both gas and electric), fuel supply contracts and energy derivatives designed to manage the risk around generation and load. While Power manages its risk at the portfolio level, it also monitors separately the risk of its trading activities and its hedges. Non-trading MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM derivatives that are not hedges are included in the trading VaR.

The VaR models used by Power are variance/covariance models adjusted for the delta of positions with a 95% one-tailed confidence level and a one-day holding period for the MTM trading and non- trading activities and a 95% one-tailed confidence level with a one-week holding period for the portfolio VaR. The models assume no new positions throughout the holding periods, whereas Power actively manages its portfolio.

Reduced trading activities by Power during 2007 have resulted in less trading risk. As of each of December 31, 2007 trading VaR was less than $1 million.

For the Year Ended December 31, 2007

Trading VaR

Non-Trading
MTM VaR

(Millions)

95% Confidence Level, One-Day Holding Period, One-Tailed:

Period End

$

*

$

48

Average for the Period

$

*

$

45

High

$

1

$

61

Low

$

*

$

29

99% Confidence Level, One-Day Holding Period, Two-Tailed:

Period End

$

1

$

75

Average for the Period

$

*

$

71

High

$

1

$

95

Low

$

*

$

45

*

less than $1 million

Interest Rates

PSEG, Power and PSE&G

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. It is the policy of PSEG, Power and PSE&G to manage interest rate risk through the use of fixed and floating rate debt, interest rate swaps and interest rate lock agreements. PSEG, Power and PSE&G manage their respective interest rate exposures by maintaining a targeted ratio of fixed and floating rate debt. As of December 31, 2007, a hypothetical 10% increase in market interest rates would result in $2 million of additional annual interest costs related to debt at PSEG. In addition, as of December 31, 2007, a hypothetical 10% decrease in market interest rates would result in a $227 million increase in the fair value of debt of PSEG and its subsidiaries, including $116 million at PSE&G and $95 million at Power.

Debt and Equity Securities

PSEG, Power and PSE&G

PSEG has approximately $3.4 billion invested in its pension plans. Although fluctuations in market prices of securities within this portfolio do not directly affect PSEG s earnings in the current period, changes in the value of these investments could affect PSEG s future contributions to these plans, its financial position if its accumulated benefit obligation under its pension plans exceeds the fair value of its pension funds and future earnings as PSEG could be required to adjust pension expense and its assumed rate of return.

Power

Power s NDT Funds are comprised of both fixed income and equity securities totaling $1.3 billion as of December 31, 2007. The fair value of equity securities is determined independently each month by the Trustee. As of December 31, 2007, the portfolio was comprised of approximately $759 million of equity securities and approximately $517 million in fixed income securities. The fair market value of the assets in the NDT Funds will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2007, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Funds by approximately $76 million.

Power uses duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Funds is the Lehman Brothers Aggregate Bond Index, which currently has duration of 4.41 years and a yield of 6.97%. The portfolio s value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2007, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $21 million.

Credit Risk

PSEG, Power and PSE&G

Credit risk relates to the risk of loss that PSEG, Power and PSE&G would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG, Power and PSE&G have established credit policies that they believe significantly minimize credit risk. These policies include an evaluation of potential counterparties financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which may allow for the netting of positive and negative exposures associated with a single counterparty.

Power

Counterparties expose Power s operations to credit losses in the event of non-performance or non-payment. Power has a credit management process, which is used to assess, monitor and mitigate counterparty exposure for Power and its subsidiaries. Power s counterparty credit limits are based on a scoring model that considers a variety of factors, including leverage, liquidity, profitability, credit ratings and risk management capabilities. Power has entered into payment netting agreements or enabling agreements that allow for payment netting with the majority of its large counterparties, which reduce Power s exposure to counterparty risk by providing the offset of amounts payable to the counterparty against amounts receivable from the counterparty. In the event of non-performance or non- payment by a major counterparty, there may be a material adverse impact on Power s and its subsidiaries financial condition, results of operations or net cash flows. As of December 31, 2007, approximately 80% of the credit exposure (MTM plus net receivables and payables, less cash collateral) for Power s operations was with investment grade counterparties. The majority of the credit exposure with non-investment grade counterparties was with certain companies that supply fuel (primarily coal) to Power. Therefore, this exposure relates to the risk of a counterparty performing under its obligations rather than payment risk. In the first quarter of 2008, exposure to coal counterparties increased, reducing credit exposure with investment grade counterparties to 64%. Coal prices have increased materially since the beginning of 2008.

PSE&G

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

Global

Global has credit risk with respect to its counterparties to PPAs and other parties.

Resources

Resources has credit risk related to its investments in leveraged leases, totaling $781 million, which is net of deferred taxes of $2 billion, as of December 31, 2007. These investments are largely concentrated in the energy industry. As of December 31, 2007, 66% of counterparties in the lease portfolio were rated investment grade by both S&P and Moody s. As of December 31, 2007, the weighted average credit rating of the lessees in Resources leasing portfolio was A /A3 by S&P and Moody s respectively. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a market downturn or degradation in operating performance of the leased assets.

In any lease transaction, in the event of a default, Resources would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Resources would record a pre-tax write- off up to its gross investment, including deferred taxes, in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Resources portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to PSEG s financial position, results of operations and net cash flows.

Other Supplemental Information Regarding Market Risk

Power

The following table describes the drivers of Power s energy trading and marketing activities and Operating Revenues included in its Condensed Consolidated Statement of Operations for the year ended December 31, 2007. Normal operations and hedging activities represent the marketing of electricity available from Power s owned or contracted generation sold into the wholesale market. As the information in this table highlights, MTM activities represent a small portion of the total Operating Revenues for Power. Activities accounted for under the accrual method, including normal purchases and sales, account for the majority of the revenue. The MTM activities reported here are those relating to changes in fair value due to external movement in prices. For additional information, see Note 11. Financial Risk Management Activities.

Operating Revenues
For the Year Ended December 31, 2007

Normal Operations and Hedging(A)

Trading

Total

(Millions)

MTM Activities:

Unrealized MTM Gains (Losses)

Changes in Fair Value of Open Position

$

(6

)

$

(3

)

$

(9

)

Realization at Settlement of Contracts

(15

)

10

(5

)

Total Change in Unrealized Fair Value

(21

)

7

(14

)

Realized Net Settlement of Transactions Subject to MTM

15

(10

)

5

Net MTM Losses

(6

)

(3

)

(9

)

Accrual Activities:

Accrual Activities Revenue, Including Hedge Reclassifications

6,805

6,805

Total Operating Revenues

$

6,799

$

(3

)

$

6,796

(A)

Includes derivative contracts that Power enters into to hedge anticipated exposures related to its owned and contracted generation supply, all asset backed transactions and hedging activities, but excludes owned and contracted generation assets.

The following table indicates Power s energy contracts, including Power s hedging activity related to asset backed transactions and derivative instruments that qualify for hedge accounting under SFAS 133. This table presents amounts segregated by portfolio which are then netted for those counterparties with whom Power has the right to offset and therefore, are not necessarily indicative of amounts presented on the Condensed Consolidated Balance Sheets since balances with many counterparties are subject to offset and are shown net on the Condensed Consolidated Balance Sheets regardless of the portfolio in which they are included.

Energy Contract Net Assets/Liabilities
As of December 31, 2007

Normal Operations and Hedging

Trading

Total

(Millions)

MTM Energy Assets

Current Assets

$

46

$

13

$

59

Noncurrent Assets

5

1

6

Total MTM Energy Assets

51

14

65

MTM Energy Liabilities

Current Liabilities

$

(365

)

$

(10

)

$

(375

)

Noncurrent Liabilities

(179

)

(1

)

(180

)

Total MTM Energy Liabilities

(544

)

(11

)

(555

)

Total MTM Energy Contract Net (Liabilities) Assets

$

(493

)

$

3

$

(490

)

The following table presents the maturity of net fair value of MTM energy contracts.

Maturity of Net Fair Value of MTM Energy Contracts
As of December 31, 2007

Maturities within

2008

2009

2010
2011

Total

(Millions)

Trading

$

3

$

$

$

3

Normal Operations and Hedging

(319

)

(110

)

(64

)

(493

)

Total Net Unrealized Losses on MTM Contracts

$

(316

)

$

(110

)

$

(64

)

$

(490

)

Wherever possible, fair values for these contracts were obtained from quoted market sources. For contracts where no quoted market exists, modeling techniques were employed using assumptions reflective of current market rates, yield curves and forward prices as applicable to interpolate certain prices. The effect of using such modeling techniques is not material to Power s financial results.

Global

The following table describes the drivers of Global s marketing activities and Operating Revenues included in PSEG s Condensed Consolidated Statement of Operations for the year ended December 31, 2007. Normal operations and hedging activities represent the marketing of electricity available from Global s owned generation sold into the market. Activities accounted for under the accrual method account for the majority of the revenue. The MTM activities reported here are those relating to changes in fair value due to external movement in prices.

Operating Revenues
For the Year Ended December 31, 2007

Normal
Operations and
Hedging(A)

(Millions)

MTM Activities:

Unrealized MTM Gains (Losses)

Changes in Fair Value of Open Position

$

26

Realization at Settlement of Contracts

Total Change in Unrealized Fair Value

26

Accrual Activities:

Accrual Activities Revenue, Including Hedge Reclassifications

769

Total Operating Revenues

$

795

(A)

Includes derivative contracts that Global enters into to hedge anticipated exposures related to its owned and contracted generation supply.

The following table indicates Global s energy contract net assets.

Energy Contract Net Assets/Liabilities
As of December 31, 2007

Normal Operations and Hedging

(Millions)

MTM Energy Assets

Current Assets

$

18

Noncurrent Assets

45

Total MTM Energy Assets

63

MTM Energy Liabilities

Current Liabilities

$

Noncurrent Liabilities

Total MTM Energy Liabilities

Total MTM Energy Contract Net Assets

$

63

The following table presents the maturity of net fair value of MTM energy contracts.

Maturity of Net Fair Value of MTM Energy Contracts
As of December 31, 2007

Maturities within

2008

2009

2010
2011

Total

(Millions)

Total Net Unrealized Losses on MTM Contracts (A)

$

18

$

24

$

21

$

63

(A)

The maturity of fair value of MTM Energy contracts as of December 31, 2007 includes $34 million of deferred inception losses which will be charged to Retained Earnings in January 2008 as a result of the adoption of SFAS 157. See Note 2. Recent Accounting Standards for additional information.

Wherever possible, fair values for these contracts were obtained from quoted market sources. For contracts where no quoted market exists, modeling techniques were employed using assumptions reflective of current market rates, yield curves and forward prices as applicable to interpolate.

PSEG and Power

The following table identifies losses on cash flow hedges that are currently in Accumulated Other Comprehensive Loss, a separate component of equity. Power uses forward sale and purchase contracts, swaps and firm transmission rights contracts to hedge forecasted energy sales from its generation stations and its contracted supply obligations. Power also enters into swaps, options and futures transactions to hedge the price of fuel to meet its fuel purchase requirements for generation. PSEG and Power are subject to the risk of fluctuating interest rates in the normal course of business. PSEG s policy is to manage interest rate risk through the use of fixed rate debt, floating rate debt and interest rate derivatives. The table also provides an estimate of the losses, net of taxes that are expected to be reclassified out of Accumulated Other Comprehensive Loss and into earnings over the next twelve months.

Cash Flow Hedges Included in Accumulated Other Comprehensive Loss
As of December 31, 2007

Accumulated Other Comprehensive Loss	
Portion Expected to be Reclassified in next 12 months	
(Millions)	
Commodities	

$

(251

)

$

(147

)

Interest Rates

(8

)

(2

)

Net Cash Flow Hedge Loss Included in Accumulated Other Comprehensive Loss

$

(259

)

$

(149

)

Power

Credit Risk

The following table provides information on Power s credit exposure, net of collateral, as of December 31, 2007. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value on open positions. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the maturity of a company s credit risk by credit rating of the counterparties.

Schedule of Credit Risk Exposure on Energy Contracts Net Assets
As of December 31, 2007

Rating

Current Exposure

Securities Held as Collateral

Net Exposure

Number of Counterparties >10%

Net Exposure of Counterparties >10%

(Millions)

(Millions)

Investment Grade External Rating

$

449

$

35

$

449

1

(A)

$

351

Non-Investment Grade External Rating

3

1

2

Investment Grade No External Rating

2

2

Non-Investment Grade No External Rating

112

1

112

1

92

Total

$

566

$

37

$

565

2

$

443

(A)

PSE&G is a counterparty with net exposure of $351 million.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. When letters of credit are posted, exposure is not reduced; it is shifted to a more creditworthy entity. As of December 31, 2007, Power had 137 active counterparties.

ITEM 8.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined 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 make representations only as to itself and make no representations as to any other company.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED:

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, common stockholders equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109*.

As discussed in Note 2 to the consolidated financial statements, on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company s internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2008 expressed an unqualified opinion on the Company s internal control over financial reporting.

DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, member s equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109*.

As discussed in Note 2 to the consolidated financial statements, on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Sole Stockholder and Board of Directors of
PUBLIC SERVICE ELECTRIC AND GAS COMPANY:

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the Company) as of December 31, 2007 and 2006, and the related consolidated statements of operations, common stockholder s equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15. These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 2 to the consolidated financial statements, on January 1, 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109.*

As discussed in Note 2 to the consolidated financial statements, on December 31, 2006, the Company adopted Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2008

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
(Millions, except for share data)

For The Years Ended December 31,

2007

2006

2005

OPERATING REVENUES

$

12,853

$

11,762

$

11,849

OPERATING EXPENSES

Energy Costs

6,523

6,553

6,882

Operation and Maintenance

2,419

2,221

2,224

Write-down of Assets

16

318

Depreciation and Amortization

783

811

714

Taxes Other Than Income Taxes

139

133

141

Total Operating Expenses

9,880

10,036

9,961

Income from Equity Method Investments

116

120

124

OPERATING INCOME

3,089

1,846

2,012

Other Income

282

201

229

Other Deductions

(259

)

(113

)

(85

)

Interest Expense

(729

)

(791

)

(766

)

Preferred Stock Dividends

(4

)

(4

)

(4

)

INCOME FROM CONTINUING OPERATIONS BEFORE
INCOME TAXES

2,379

1,139

1,386

Income Tax Expense

(1,060

)

(460

)

(549

)

INCOME FROM CONTINUING OPERATIONS

1,319

679

837

Income (Loss) from Discontinued Operations, including Gain (Loss) on Disposal, net of tax (expense) benefit of ($161), ($115), and $36 for the years ended 2007, 2006 and 2005, respectively

16

60

(159

)

INCOME BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE

1,335

739

678

Cumulative Effect of a Change in Accounting Principle, net of tax benefit of $11

(17

)

NET INCOME

$

1,335

$

739

$

661

WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):

BASIC

507,560

503,356

480,594

DILUTED

508,813

504,628

488,812

EARNINGS PER SHARE:

BASIC

INCOME FROM CONTINUING OPERATIONS

$

2.60

$

1.35

$

1.74

NET INCOME

$

2.63

$

1.47

$

1.38

DILUTED

INCOME FROM CONTINUING OPERATIONS

$

2.59

$

1.34

$

1.71

NET INCOME

$

2.62

$

1.46

$

1.35

DIVIDENDS PAID PER SHARE OF COMMON STOCK

$

1.17

$

1.14

$

1.12

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
(Millions)

December 31,	2007	2006
ASSETS		

CURRENT ASSETS

Cash and Cash Equivalents

$

381

$

106

Accounts Receivable, net of allowances of $46 and $47 in 2007 and 2006, respectively

1,639

1,257

Unbilled Revenues

353

328

Fuel

793

848

Materials and Supplies

296

275

Prepayments

91

72

Restricted Funds

114

79

Derivative Contracts

70

109

Assets of Discontinued Operations

1,162

1,618

Assets Held for Sale

40

Other

29

45

Total Current Assets

4,928

4,777

PROPERTY, PLANT AND EQUIPMENT

19,310

18,094

Less: Accumulated Depreciation and Amortization

(6,035

)

(5,676

)

Net Property, Plant and Equipment

13,275

12,418

NONCURRENT ASSETS

Regulatory Assets

5,165

5,694

Long-Term Investments

3,246

3,868

Nuclear Decommissioning Trust (NDT) Funds

1,276

1,256

Other Special Funds

164

147

Goodwill and Other Intangibles

64

62

Derivative Contracts

53

55

Other

221

275

Total Noncurrent Assets

10,189

11,357

TOTAL ASSETS	$	28,392	$	28,552

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
(Millions)

December 31,

2007

2006

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES

Long-Term Debt Due Within One Year

$

1,123

$

836

Commercial Paper and Loans

65

381

Accounts Payable

1,094

916

Derivative Contracts

393

316

Accrued Interest

113

122

Accrued Taxes

204

147

Deferred Income Taxes

106

Clean Energy Program

135

120

Liabilities of Discontinued Operations

520

422

Other

537

456

Total Current Liabilities

4,290

3,716

NONCURRENT LIABILITIES

Deferred Income Taxes and Investment Tax Credits (ITC)

4,454

4,440

Regulatory Liabilities

419

646

Asset Retirement Obligations

542

509

Other Postretirement Benefit (OPEB) Costs

1,003

1,090

Accrued Pension Costs

203

326

Clean Energy Program

14

133

Environmental Costs

649

421

Derivative Contracts

221

204

Long-Term Accrued Taxes

423

Other

133

140

Total Noncurrent Liabilities

8,061

7,909

COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)

CAPITALIZATION

LONG-TERM DEBT

Long-Term Debt

6,783

7,637

Securitization Debt

1,530

1,708

Project Level, Non-Recourse Debt

349

569

Debt Supporting Trust Preferred Securities

186

Total Long-Term Debt

8,662

10,100

SUBSIDIARIES   PREFERRED SECURITIES

Preferred Stock Without Mandatory Redemption, $100 par value, 7,500,000 authorized; issued and outstanding, 2007 and 2006   795,234 shares

80

80

COMMON STOCKHOLDERS EQUITY

Common Stock, no par, authorized 1,000,000,000 shares; issued; 2007 533,556,660 shares; 2006 532,744,880 shares

4,732

4,661

Treasury Stock, at cost; 2007 25,033,656 shares; 2006 27,454,064 shares

(478

)

(516

)

Retained Earnings

3,261

2,710

Accumulated Other Comprehensive Loss

(216

)

(108

)

Total Common Stockholders Equity

7,299

6,747

Total Capitalization

16,041

16,927

TOTAL LIABILITIES AND CAPITALIZATION

$

28,392

$

28,552

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)

For The Years Ended
December 31,

2007

2006

2005

CASH FLOWS FROM OPERATING ACTIVITIES

Net Income

$

1,335

$

739

$

661

Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:

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

(48

)

(19

)

178

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

17

Gain on Disposition of Property, Plant and Equipment

(3

)

(5

)

(8

)

Write-Down of Property, Plant and Equipment

44

Write-Down of Project Investments

16

7

22

Depreciation and Amortization

802

850

767

Amortization of Nuclear Fuel

95

97

94

Provision for Deferred Income Taxes (Other than Leases) and ITC

119

(89

)

224

Non-Cash Employee Benefit Plan Costs

185

237

235

Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes

70

64

(27

)

(Gain) Loss on Sale of Investments

(173

)

253

(122

)

Cost of Removal

(37

)

(33

)

(30

)

Undistributed Earnings from Affiliates

(10

)

(44

)

(46

)

Foreign Currency Transaction Loss

5

Unrealized Losses (Gains) on Energy Contracts and Other Derivatives

22

(30

)

20

(Under) Over Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs

(71

)

111

109

Under Recovery of Societal Benefits Charge (SBC)

(53

)

(175

)

(158

)

Net Realized Gains and Income from NDT Funds

(48

)

(64

)

(125

)

Other Non-Cash Charges

6

18

51

Net Change in Certain Current Assets and Liabilities

(169

)

146

(678

)

Employee Benefit Plan Funding and Related Payments

(96

)

(148

)

(240

)

Proceeds from the Withdrawal of Partnership Interests and Other Distributions

10

64

Other

(24

)

(43

)

(59

)

Net Cash Provided By Operating Activities

1,918

1,931

949

CASH FLOWS FROM INVESTING ACTIVITIES

Additions to Property, Plant and Equipment

(1,348

)

(1,015

)

(1,053

)

Proceeds from Collection of Notes Receivable

120

Proceeds from Sale of Discontinued Operations

600

494

218

Proceeds from Sale of Property, Plant and Equipment

43

5

11

Proceeds from the Sale of Investments and Return of Capital from Partnerships

703

251

315

Proceeds from NDT Funds Sales

1,672

1,405

3,223

Investment in NDT Funds

(1,703

)

(1,427

)

(3,232

)

Restricted Funds

(41

)

(6

)

(49

)

NDT Funds Interest and Dividends

48

40

35

Other

25

10

12

Net Cash Provided by (Used In) Investing Activities

(1

)

(243

)

(400

)

CASH FLOWS FROM FINANCING ACTIVITIES

Net Change in Commercial Paper and Loans

(317

)

281

(538

)

Issuance of Long-Term Debt

434

250

728

Issuance of Non-Recourse Debt

163

18

Issuance of Common Stock

83

83

533

Redemptions of Long-Term Debt

(551

)

(1,431

)

(125

)

Repayment of Non-Recourse Debt

(57

)

(51

)

(37

)

Redemption of Securitization Debt

(170

)

(163

)

(146

)

Redemption of Debt Underlying Trust Securities

(660

)

(203

)

(387

)

Cash Dividends Paid on Common Stock

(594

)

(574

)

(541

)

Other

27

(26

)

(47

)

Net Cash Used In Financing Activities

(1,642

)

(1,834

)

(542

)

Effect of Exchange Rate Change

(1

)

1

Net Increase (Decrease) in Cash and Cash Equivalents

275

(147

)

8

Cash and Cash Equivalents at Beginning of Period

106

253

245

Cash and Cash Equivalents at End of Period

$

381

$

106

$

253

Supplemental Disclosure of Cash Flow Information:

Income Taxes Paid

$

678

$

386

$

103

Interest Paid, Net of Amounts Capitalized

$

715

$

773

$

793

See Notes to Consolidated Financial Statements.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS EQUITY
(Millions)

Common Stock

Treasury Stock

Retained Earnings

Accumulated
Other
Comprehensive
Loss

Total

Shs.

Amount

Shs.

Amount

Balance as of January 1, 2005

528

$

4,569

(52

)

$

(978

)

$

2,425

$

(272

)

$

5,744

Net Income

661

661

Other Comprehensive Income (Loss), net of tax:

Currency Translation Adjustment, net of tax

84

84

Available for Sale Securities, net of tax

(30

)

(30

)

Change in Fair Value of Derivative Instruments, net of tax

(573

)

(573

)

Reclassification Adjustments for Net Amounts included in Net Income, net of tax

182

182

Settlement Adjustments Related to Projects Under Construction

(2

)

(2

)

Minimum Pension Liability Adjustment,
net of tax

2

2

Other Comprehensive Loss

(337

)

Comprehensive Income

324

Cash Dividends on Common Stock

(541

)

(541

)

Issuance of Common Stock

2

104

24

429

533

Issuance Costs and Other

(55

)

17

(38

)

Balance as of December 31, 2005

530

$

4,618

(28

)

$

(532

)

$

2,545

$

(609

)

$

6,022

Net Income

739

739

Other Comprehensive Income (Loss), net of tax:

Currency Translation Adjustment,
net of tax

154

154

Available for Sale Securities, net of tax

37

37

Change in Fair Value of Derivative Instruments, net of tax

343

343

Reclassification Adjustments for Net Amounts included in Net Income, net of tax

114

Sale of Investments

55

55

Minimum Pension Liability Adjustment, net of tax

3

3

Other Comprehensive Income

706

Comprehensive Income

1,445

Adjustment to initially apply FASB Statement 158, net of tax

(205

)

(205

)

Cash Dividends on Common Stock

(574

)

(574

)

Issuance of Common Stock

2

68

1

15

83

Issuance Costs and Other

(25

)

1

(24

)

Balance as of December 31, 2006

532

$

4,661

(27

)

$

(516

)

$

2,710

$

(108

)

$

6,747

Net Income

1,335

1,335

Other Comprehensive Income (Loss), net of tax:

Currency Translation Adjustment,
net of tax

(3

)

(3

)

Available for Sale Securities, net of tax

(10

)

(10

)

Change in Fair Value of Derivative Instruments, net of tax

(290

)

(290

)

Reclassification Adjustments for Net Amounts included in Net Income, net of tax

144

144

Adjustment for application of FASB Statement 158, net of tax

50

50

Sale of Investments

1

1

Other Comprehensive Loss

(108

)

Comprehensive Income

1,227

Adjustment to initially apply FSP13-2, net of tax

(67

)

(67

)

Adjustment to initially apply FIN 48, net of tax

(123

)

(123

)

Cash Dividends on Common Stock

(594

)

(594

)

Issuance of Common Stock

2

35

2

48

83

Issuance Costs and Other

36

(10

)

26

Balance as of December 31, 2007

534

$

4,732

(25

)

$

(478

)

$

3,261

$

(216

)

$

7,299

See Notes to Consolidated Financial Statements.

PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
(Millions)

For The Years Ended December 31,

2007

2006

2005

OPERATING REVENUES

$

6,796

$

6,057

$

6,027

OPERATING EXPENSES

Energy Costs

3,975

3,955

4,266

Operation and Maintenance

1,001

958

939

Write-Down of Assets

44

Depreciation and Amortization

140

140

114

Total Operating Expenses

5,116

5,097

5,319

OPERATING INCOME

1,680

960

708

Other Income

239

157

187

Other Deductions

(170

)

(91

)

(43

)

Interest Expense

(159

)

(148

)

(100

)

INCOME FROM CONTINUING OPERATIONS BEFORE
INCOME TAXES

1,590

878

752

Income Tax Expense

(641

)

(363

)

(318

)

INCOME FROM CONTINUING OPERATIONS

949

515

434

Loss from Discontinued Operations, net of tax benefit of $5, $22 and $33 for the years ended 2007, 2006 and 2005, respectively

(8

)

(31

)

(48

)

Loss on Disposal of Discontinued Operations, net of tax benefit of $144 for the year ended 2006

(208

)

(178

)

INCOME BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE

941

276

208

Cumulative Effect of a Change in Accounting Principle, net of tax benefit of $11 for the year ended 2005

(16

)

EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE
GROUP INCORPORATED

$

941

$

276

$

192

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

PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
(Millions)

December 31,

2007

2006

ASSETS

CURRENT ASSETS

Cash and Cash Equivalents

$

11

$

13

Accounts Receivable

619

430

Accounts Receivable   Affiliated Companies, net

441

495

Fuel

791

846

Materials and Supplies

220

202

Energy Contracts

51

93

Restricted Cash

50

Prepayments

26

17

Assets of Discontinued Operations

325

Assets Held for Sale

40

Other

31

9

Total Current Assets

2,240

2,470

PROPERTY, PLANT AND EQUIPMENT

6,565

5,868

Less: Accumulated Depreciation and Amortization

(1,814

)

(1,638

)

Net Property, Plant and Equipment

4,751

4,230

NONCURRENT ASSETS

Nuclear Decommissioning Trust (NDT) Funds

1,276

1,256

Goodwill

16

16

Other Intangibles

35

35

Other Special Funds

45

42

Energy Contracts

8

29

Other

57

50

Total Noncurrent Assets

1,437

1,428

TOTAL ASSETS

$

8,428

$

8,128

LIABILITIES AND MEMBER S EQUITY

CURRENT LIABILITIES

Accounts Payable

$

649

$

589

Short-Term Loan from Affiliate

238

54

Energy Contracts

368

294

Accrued Interest

34

34

Other

118

95

Total Current Liabilities

1,407

1,066

NONCURRENT LIABILITIES

Deferred Income Taxes and Investment Tax Credits (ITC)

176

48

Asset Retirement Obligations

309

287

Other Postretirement Benefit (OPEB) Costs

129

138

Energy Contracts

181

170

Accrued Pension Costs

70

106

Environmental Costs

55

54

Long-Term Accrued Taxes

26

Other

12

18

Total Noncurrent Liabilities

958

821

COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)

LONG-TERM DEBT

Total Long-Term Debt

2,902

2,818

MEMBER S EQUITY

Contributed Capital

2,000

2,000

Basis Adjustment

(986

)

(986

)

Retained Earnings

2,438

2,586

Accumulated Other Comprehensive Loss

(291

)

(177

)

Total Member s Equity

3,161

3,423

TOTAL LIABILITIES AND MEMBER S EQUITY

$

8,428

$

8,128

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

PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)

For The Years Ended December 31,

2007

2006

2005

CASH FLOWS FROM OPERATING ACTIVITIES

Net Income

$

941

$

276

$

192

Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:

Loss on Disposal of Discontinued operations, net of tax

208

178

Cumulative Effect of a Change in Accounting Principle

16

Write-down of Property, Plant and Equipment

44

Gain on Disposition of Property, Plant and Equipment

(1

)

(5

)

Depreciation and Amortization

140

157

136

Amortization of Nuclear Fuel

95

97

94

Interest Accretion on Asset Retirement Obligations

23

33

28

Provision for Deferred Income Taxes and ITC

222

34

276

Net Realized and Unrealized Losses on Energy Contracts and Other Derivatives

33

5

17

Non-Cash Employee Benefit Plan Costs

28

46

46

Net Realized Gains and Income from NDT Funds

(48

)

(64

)

(125

)

Net Change in Working Capital:

Fuel, Materials and Supplies

37

(45

)

(214

)

Accounts Receivable

(189

)

432

(122

)

Accounts Payable

15

(181

)

(247

)

Accounts Receivable/Payable Affiliated Companies, net

(65

)

122

(91

)

Other Current Assets and Liabilities

(16

)

(5

)

(27

)

Employee Benefit Plan Funding and Related Payments

(15

)

(37

)

(58

)

Other

4

(78

)

42

Net Cash Provided By Operating Activities

1,205

1,043

136

CASH FLOWS FROM INVESTING ACTIVITIES

Additions to Property, Plant and Equipment

(715

)

(418

)

(476

)

Sales of Property, Plant and Equipment

40

1

8

Proceeds from NDT Funds Sales

1,672

1,405

3,223

NDT Funds Interest and Dividends

48

40

35

Investment in NDT Funds

(1,703

)

(1,427

)

(3,232

)

Restricted Funds

(50

)

Proceeds from Sale of Discontinued Operations

325

218

Other

(17

)

9

(18

)

Net Cash Used In Investing Activities

(400

)

(390

)

(242

)

CASH FLOWS FROM FINANCING ACTIVITIES

Issuance of Recourse Long-Term Debt

84

Redemption of Long-Term Debt

(500

)

Cash Dividend Paid

(1,075

)

Short-Term Loan Affiliated Company, net

184

(148

)

104

Net Cash (Used in) Provided by Financing Activities

(807

)

(648

)

104

Net (Decrease) Increase in Cash and Cash Equivalents

(2

)

5

(2

)

Cash and Cash Equivalents at Beginning of Period

13

8

10

Cash and Cash Equivalents at End of Period

$

11

$

13

$

8

Supplemental Disclosure of Cash Flow Information:

Income Taxes Paid (Benefits Received)

$

345

$

(23

)

$

(23

)

Interest Paid, Net of Amounts Capitalized

$

169

$

139

$

139

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

PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CAPITALIZATION AND MEMBER S EQUITY
(Millions)

Contributed Capital

Basis Adjustment

Retained Earnings

Accumulated Other Comprehensive Income (Loss)

Total Member s Equity

Balance as of January 1, 2005

$

2,000

$

(986

)

$

2,118

$

(49

)

$

3,083

Net Income

192

192

Other Comprehensive Income (Loss), net of tax:

Available for Sale Securities, net of tax

(30

)

(30

)

Minimum Pension Liability Adjustment, net of tax

1

1

Change in Fair Value of Derivative Instruments, net of tax

(589

)

(589

)

Reclassification Adjustments for Net Amount included in Net Income,
net of tax

180

180

Other Comprehensive Loss

(438

)

Comprehensive Loss

(246

)

Balance as of December 31, 2005

$

2,000

$

(986

)

$

2,310

$

(487

)

$

2,837

Net Income

276

276

Other Comprehensive Income (Loss),
net of tax:

Available for Sale Securities, net of tax

37

37

Minimum Pension Liability Adjustment, net of tax

(4

)

(4

)

Change in Fair Value of Derivative Instruments, net of tax

343

343

Reclassification Adjustments for Net Amount included in Net Income,
net of tax

107

107

Other Comprehensive Income

483

Comprehensive Income

759

Adjustment to initially apply FASB Statement 158, net of tax

(173

)

(173

)

Balance as of December 31, 2006

$

2,000

$

(986

)

$

2,586

$

(177

)

$

3,423

Net Income

941

941

Other Comprehensive Income (Loss),
net of tax:

Available for Sale Securities, net of tax

(10

)

(10

)

Adjustment for FASB Statement 158,
net of tax

38

38

Change in Fair Value of Derivative Instruments, net of tax

(287

)

(287

)

Reclassification Adjustments for Net Amount included in Net Income, net of tax

145

145

Other Comprehensive Loss

(114

)

Comprehensive Income

827

Adjustment to initially apply FIN 48, net of tax

(14

)

(14

)

Cash Dividends Paid

(1,075

)

(1,075

)

Balance as of December 31, 2007

$

2,000

$

(986

)

$

2,438

$

(291

)

$

3,161

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(Millions)

For The Years Ended December 31,

2007

2006

2005

OPERATING REVENUES

$

8,493

$

7,569

$

7,514

OPERATING EXPENSES

Energy Costs

5,498

4,884

4,756

Operation and Maintenance

1,308

1,160

1,151

Depreciation and Amortization

591

620

553

Taxes Other Than Income Taxes

139

133

141

Total Operating Expenses

7,536

6,797

6,601

OPERATING INCOME

957

772

913

Other Income

16

25

15

Other Deductions

(4

)

(3

)

(3

)

Interest Expense

(332

)

(346

)

(342

)

INCOME BEFORE INCOME TAXES

637

448

583

Income Tax Expense

(257

)

(183

)

(235

)

NET INCOME

380

265

348

Preferred Stock Dividends

(4

)

(4

)

(4

)

EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

$

376

$

261

$

344

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
(Millions)

December 31,

2007

2006

ASSETS

CURRENT ASSETS

Cash and Cash Equivalents

$

32

$

28

Accounts Receivable, net of allowances of $45 in 2007 and $46 in 2006

995

805

Unbilled Revenues

353

328

Materials and Supplies

53

50

Prepayments

57

14

Restricted Funds

7

12

Derivative Contracts

1

2

Deferred Income Taxes

44

36

Total Current Assets

1,542

1,275

PROPERTY, PLANT AND EQUIPMENT

11,531

11,061

Less: Accumulated Depreciation and Amortization

(3,920

)

(3,794

)

Net Property, Plant and Equipment

7,611

7,267

NONCURRENT ASSETS

Regulatory Assets

5,165

5,694

Long-Term Investments

153

149

Other Special Funds

57

53

Other

109

115

Total Noncurrent Assets

5,484

6,011

TOTAL ASSETS	$ 14,637	$ 14,553

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
(Millions)

December 31,

2007

2006

LIABILITIES AND CAPITALIZATION

CURRENT LIABILITIES

Long-Term Debt Due Within One Year

$

429

$

284

Commercial Paper and Loans

65

31

Accounts Payable

325

254

Accounts Payable Affiliated Companies, net

559

645

Accrued Interest

56

55

Accrued Taxes

29

3

Clean Energy Program

135

120

Derivative Contracts

20

2

Other

318

319

Total Current Liabilities

1,936

1,713

NONCURRENT LIABILITIES

Deferred Income Taxes and ITC

2,440

2,517

Other Postretirement Benefit (OPEB) Costs

821

898

Accrued Pension Costs

63

133

Regulatory Liabilities

419

646

Clean Energy Program

14

133

Environmental Costs

594

367

Asset Retirement Obligations

231

221

Derivative Contracts

36

18

Long-Term Accrued Taxes

75

Other

9

6

Total Noncurrent Liabilities

4,702

4,939

COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)

CAPITALIZATION

LONG-TERM DEBT

Long-Term Debt

3,102

3,003

Securitization Debt

1,530

1,708

Total Long-Term Debt

4,632

4,711

PREFERRED SECURITIES

Preferred Stock Without Mandatory Redemption, $100 par value, 7,500,000 authorized; issued and outstanding, 2007 and 2006 795,234 shares

80

80

COMMON STOCKHOLDER S EQUITY

Common Stock; 150,000,000 shares authorized, 132,450,344 shares issued and outstanding

892

892

Contributed Capital

170

170

Basis Adjustment

986

986

Retained Earnings

1,237

1,061

Accumulated Other Comprehensive Income

2

1

Total Common Stockholder s Equity

3,287

3,110

Total Capitalization

7,999

7,901

TOTAL LIABILITIES AND CAPITALIZATION

$

14,637

$

14,553

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

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

For the Years Ended December 31,

2007

2006

2005

CASH FLOWS FROM OPERATING ACTIVITIES

Net Income

$

380

$

265

$

348

Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:

Depreciation and Amortization

591

620

553

Provision for Deferred Income Taxes and ITC

(118

)

(112

)

(52

)

Non-Cash Employee Benefit Plan Costs

140

169

166

Gain on Sale of Property, Plant and Equipment

(3

)

(4

)

(3

)

Non-Cash Interest Expense

12

18

16

Cost of Removal

(37

)

(33

)

(30

)

Employee Benefit Plan Funding and Related Payments

(69

)

(97

)

(154

)

Over Recovery of Electric Energy Costs (BGS and NTC)

(28

)

24

117

(Under) Over Recovery of Gas Costs

(43

)

87

(8

)

Over (Under) Recovery of SBC

(53

)

(175

)

(158

)

Other Non-Cash Charges

(4

)

(5

)

(6

)

Net Changes in Certain Current Assets and Liabilities:

Accounts Receivable and Unbilled Revenues

(218

)

220

(268

)

Materials and Supplies

(3

)

(1

)

(4

)

Prepayments

(48

)

29

6

Accrued Taxes

25

(23

)

Accrued Interest

1

(4

)

Accounts Payable

71

(32

)

36

Accounts Receivable/Payable Affiliated Companies, net

54

(72

)

79

Other Current Assets and Liabilities

1

(57

)

77

Other

27

(11

)

(31

)

Net Cash Provided By Operating Activities

678

806

684

CASH FLOWS FROM INVESTING ACTIVITIES

Additions to Property, Plant and Equipment

(570

)

(528

)

(498

)

Proceeds from the Sale of Property, Plant and Equipment

3

2

3

Restricted Funds

(1

)

(1

)

(6

)

Net Cash Used In Investing Activities

(568

)

(527

)

(501

)

CASH FLOWS FROM FINANCING ACTIVITIES

Net Change in Short-Term Debt

34

31

(105

)

Issuance of Long-Term Debt

350

250

250

Redemption of Long-Term Debt

(113

)

(322

)

(125

)

Redemption of Securitization Debt

(170

)

(163

)

(146

)

Issuance of Securitization Debt

103

Deferred Issuance Costs

(3

)

(2

)

(3

)

Cash Dividends Paid on Common Stock

(200

)

(200

)

Preferred Stock Dividends

(4

)

(4

)

(4

)

Net Cash Used In Financing Activities

(106

)

(410

)

(30

)

Net Increase (Decrease) In Cash and Cash Equivalents

4

(131

)

153

Cash and Cash Equivalents at Beginning of Period

28

159

6

Cash and Cash Equivalents at End of Period

$

32

$

28

$

159

Supplemental Disclosure of Cash Flow Information:

Income Taxes Paid

$

336

$

237

$

313

Interest Paid, Net of Amounts Capitalized

$

314

$

312

$

316

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER S EQUITY
(Millions)

Common Stock

Contributed Capital from PSEG

Basis Adjustment

Retained Earnings

Accumulated Other Comprehensive Loss

Total

Balance as of January 1, 2005

$

892

$

170

$

986

$

656

$

(4

)

$

2,700

Net Income

348

348

Other Comprehensive Loss,
net of tax:

Minimum Pension Liability Adjustment, net of tax

(1

)

(1

)

Comprehensive Income

347

Cash Dividends on Preferred Stock

(4

)

(4

)

Balance as of December 31, 2005

$

892

$

170

$

986

$

1,000

$

(5

)

$

3,043

Net Income

265

265

Other Comprehensive Income, net of tax:

Minimum Pension Liability Adjustment, net of tax

5

5

Comprehensive Income

270

Adjustment to initially apply FASB Statement 158, net of tax

1

1

Cash Dividends on Common Stock

(200

)

(200

)

Cash Dividends on Preferred Stock

(4

)

(4

)

Balance as of December 31, 2006

$

892

$

170

$

986

$

1,061

$

1

$

3,110

Net Income

380

380

Other Comprehensive Income, net of tax:

Adjustment for application of FASB Statement 158, net of tax

1

1

Comprehensive Income

381

Cash Dividends on Common Stock

(200

)

(200

)

Cash Dividends on Preferred Stock

(4

)

(4

)

Balance as of December 31, 2007

$

892

$

170

$

986

$

1,237

$

2

$

3,287

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization and Summary of Significant Accounting Policies

Organization

Public Service Enterprise Group Incorporated (PSEG)

PSEG has four principal direct wholly owned subsidiaries: PSEG Power LLC (Power), Public Service Electric and Gas Company (PSE&G), PSEG Energy Holdings L.L.C. (Energy Holdings) and PSEG Services Corporation (Services).

Power

Power is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply, energy trading and marketing and risk management function through three principal direct wholly owned subsidiaries: PSEG Nuclear LLC (Nuclear), PSEG Fossil LLC (Fossil) and PSEG Energy Resources & Trade LLC (ER&T). Nuclear and Fossil own and operate generation and generation-related facilities. ER&T is responsible for the day-to-day management of Power s portfolio. Fossil, Nuclear and ER&T are subject to regulation by the Federal Energy Regulatory Commission (FERC) and Nuclear is also subject to regulation by the Nuclear Regulatory Commission (NRC).

PSE&G

PSE&G is an operating public utility engaged principally in the transmission of electric energy and distribution of electric energy and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the FERC.

PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II) are wholly owned, bankruptcy-remote subsidiaries of PSE&G that purchased certain transition property from PSE&G and issued transition bonds secured by such property. The transition property consists principally of the rights to receive electricity consumption-based per kilowatt-hour (kWh) charges from PSE&G electric distribution customers, which represent irrevocable rights to receive amounts sufficient to recover certain of PSE&G s transition costs related to deregulation, as approved by the BPU.

Energy Holdings

Energy Holdings has two principal direct wholly owned subsidiaries: PSEG Global L.L.C. (Global), which owns and operates international and domestic projects engaged in the generation and distribution of energy and PSEG Resources L.L.C. (Resources), which has invested primarily in energy-related leveraged leases. Energy Holdings also owns Enterprise Group Development Corporation (EGDC), a commercial real estate property management business.

Services

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 an intercompany service agreement.

Principles of Consolidation

PSEG, Power and PSE&G

PSEG s, Power s and PSE&G s consolidated financial statements include their respective accounts and consolidate those entities in which they have a controlling interest or are the primary beneficiary, except for certain of PSEG s capital trusts which were deconsolidated in accordance with Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46 (revised December 2003), Consolidation of Variable

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Interest Entities (VIE) (FIN 46). Entities over which PSEG, Power and PSE&G exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All intercompany accounts and transactions are eliminated in consolidation.

Power and PSE&G

Power and PSE&G each have undivided interests in certain jointly-owned facilities and each is responsible for paying their respective ownership share of additional construction costs, fuel inventory purchases and operating expenses. All revenues and expenses related to these facilities are consolidated at their respective pro-rata ownership share in the appropriate revenue and expense categories on the Consolidated Statements of Operations. For additional information regarding these jointly-owned facilities, see Note 19. Property, Plant and Equipment and Jointly-Owned Facilities.

Accounting for the Effects of Regulation

PSE&G

PSE&G prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71). In general, SFAS 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (a regulatory asset) or record the recognition of obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities is no longer probable as a result of changes in regulation and/or PSE&G s competitive position, the associated regulatory asset or liability is charged or credited to income. Management believes that PSE&G s transmission and distribution businesses continue to meet the requirements for application of SFAS 71. For additional information, see Note 5. Regulatory Matters.

Derivative Financial Instruments

PSEG, Power and PSE&G

PSEG, Power and PSE&G use derivative financial instruments to manage risk from changes in interest rates, congestion credits, emission credit prices, commodity prices and foreign currency exchange rates, pursuant to their business plans and prudent practices.

PSEG, Power and PSE&G recognize derivative instruments, not designated as normal purchases or sales, on the balance sheet at their fair value. Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a fair value hedge (including foreign currency fair value hedges), along with changes of the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current-period earnings. Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a cash flow hedge (including foreign currency cash flow hedges) are recorded in Accumulated Other Comprehensive Income / Loss until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current-period earnings. In certain circumstances, PSEG, Power and/or PSE&G enter into derivative contracts that do not qualify as hedges or are not designated as normal purchases or sales or as cash flow hedges; in such cases, changes in fair value are recorded in current-period earnings.

Many non-trading contracts qualify for the normal purchases and normal sales exemption under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended and interpreted (SFAS 133) and are accounted for upon settlement.

For additional information regarding derivative financial instruments, see Note 11. Financial Risk Management Activities.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Revenue Recognition

Power

The majority of Power s revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power s revenue also includes changes in value of non trading energy derivative contracts that are not designated as normal purchases or sales or as hedges of other positions. Power records margins from energy trading on a net basis pursuant to accounting principles generally accepted in the U.S. (GAAP). See Note 11. Financial Risk Management Activities for further discussion.

PSE&G

PSE&G s Operating Revenues are recorded based on services rendered to customers during each accounting period. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Depreciation and Amortization

Power

Power calculates depreciation on generation-related assets under the straight-line method based on the assets estimated useful lives which are determined based on planned operations. The estimated useful lives are from three years to 20 years for general plant assets. The estimated useful lives are 30 years to 67 years for fossil production assets, 53 years to 58 years for nuclear generation assets and 76 years for pumped storage facilities.

PSE&G

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU. The depreciation rate stated as a percentage of original cost of depreciable property was 2.46% 2007, 2.84% for 2006 and 3.00% for 2005.

Taxes Other Than Income Taxes

PSE&G

Excise taxes, transitional energy facilities assessment (TEFA) and gross receipts tax (GRT) collected from PSE&G s customers are presented on the financial statements on a gross basis. As a result of New Jersey energy tax reform, effective January 1, 1998, TEFA and GRT are the residual of the prior excise tax, the New Jersey gross receipts and franchise taxes. For the years ended December 31, 2007, 2006 and 2005, combined TEFA and GRT of approximately $154 million, $146 million and $155 million, respectively, are reflected in Operating Revenues and $140 million, $132 million and $141 million, respectively, are included in Taxes Other Than Income Taxes on the Consolidated Statements of Operations.

Interest Capitalized During Construction (IDC) and Allowance for Funds Used During Construction (AFUDC)

Power

IDC represents the cost of debt used to finance construction. The amount of IDC capitalized is reported in the Consolidated Statements of Operations as a reduction of interest charges and is included in Property, Plant and Equipment on the Consolidated Balance Sheets. Power s average rate used for calculating IDC in 2007, 2006 and 2005 was 6.81%, 6.81% and 6.74%, respectively. For the years ended December 31, 2007, 2006 and 2005, Power s IDC amounted to $33 million, $41 million and $95 million, respectively.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G

AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets under the guidance of SFAS 71. The amount of AFUDC capitalized is reported in the Consolidated Statements of Operations as a reduction of interest charges. PSE&G s average rate used for calculating AFUDC in 2007, 2006 and 2005 was 5.44%, 4.99% and 3.17%, respectively. For the years ended December 31, 2007, 2006 and 2005, PSE&G s AFUDC amounted to $2.9 million, $2.0 million and $1.2 million, respectively.

Income Taxes

PSEG, Power and PSE&G

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG s subsidiaries based on the taxable income or loss of each subsidiary. Investment tax credits were deferred in prior years and are being amortized over the useful lives of the related property.

Cash and Cash Equivalents

PSEG, Power and PSE&G

Cash and cash equivalents consist primarily of working funds and highly liquid marketable securities (commercial paper and money market funds) with an original maturity of three months or less.

Materials and Supplies and Fuel

Power

Materials and supplies and fuel for Power are valued at the lower of average cost or market.

PSE&G

PSE&G s materials and supplies are carried at average cost consistent with the rate-making process.

Restricted Funds

Power, PSE&G and Energy Holdings

Power s restricted funds represent restricted cash for qualifying expenditures for solid waste disposal technology related to pollution control notes issued by Power for two of its coal-fired generation stations. PSE&G s restricted funds represent revenues collected from its retail electric customers that must be used to pay the principal, interest and other expenses associated with the securitization bonds of Transition Funding and Transition Funding II. Energy Holdings restricted funds represent cash accounts designated for maintenance costs, debt service reserves and other specific purposes as set forth in certain of PSEG Texas loan agreements.

Property, Plant and Equipment

Power

Power only capitalizes costs which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets environmental safety or efficiency. All other environmental expenditures are expensed as incurred.

PSE&G

PSE&G s additions and replacements to property, plant and equipment that are either retirement units or property record units are capitalized at original cost. The cost of maintenance, repair and replacement of

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

minor items of property is charged to appropriate expense accounts as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Other Special Funds

PSEG, Power and PSE&G

Other Special Funds represents amounts deposited to fund the qualified pension plans and to fund a Rabbi Trust which was established to meet the obligations related to three non-qualified pension plans and a deferred compensation plan.

Nuclear Decommissioning Trust (NDT) Funds

Power

As required under SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities (SFAS 115), realized gains and losses on securities in the NDT Funds are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Loss unless securities with such unrealized losses are deemed to be other-than- temporarily-impaired.

Investments in Corporate Joint Ventures and Partnerships

Generally, PSEG s interests in active joint ventures and partnerships are accounted for under the equity method of accounting where its respective ownership interests are 50% or less, it is not the primary beneficiary, as defined under FIN 46, and significant influence over joint venture or partnership operating and management decisions exists. For investments in which significant influence does not exist and PSEG is not the primary beneficiary, the cost method of accounting is applied.

Deferred Project Costs and Development Costs

Power

Power capitalizes all direct external and incremental direct internal costs related to project development once a project reaches certain milestones. On Power s Consolidated Balance Sheets, deferred project costs are recorded in Construction Work in Progress. These costs are amortized on a straight-line basis over the lives of the related project assets. Such amortization commences upon the date of commercial operation. Development costs related to unsuccessful projects are charged to expense.

Basis Adjustment

Power and PSE&G

Power and PSE&G have recorded a Basis Adjustment on their Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, Power and PSE&G, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, approximately $986 million, net of tax, was recorded as a Basis Adjustment on Power s and PSE&G s Consolidated Balance Sheets. The $986 million is a reduction of Power s Member s Equity and an addition to PSE&G s Common Stockholder s Equity. These amounts are eliminated on PSEG s consolidated financial statements.

Stock Split

PSEG

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

held. The additional shares resulting from the stock split were distributed on February 4, 2008. All share and per share amounts in the consolidated results of operations and financial position as well as in the notes to the financial statements retroactively reflect the effect of the stock split.

Use of Estimates

PSEG, Power and PSE&G

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may materially differ from estimated amounts.

Reclassifications

PSEG, Power and PSE&G

Certain reclassifications have been made to the prior years financial statements to conform to the current year presentation. The reclassifications relate primarily to recording revenue and related expenses on certain transactions on a net basis versus gross.

Note 2. Recent Accounting Standards

The following accounting standards were issued by the Financial Accounting Standards Board (FASB) but have not yet been adopted by PSEG, Power and PSE&G.

SFAS No. 157, Fair Value Measurements (SFAS 157)

PSEG, Power and PSE&G

In September 2006, the FASB issued SFAS 157 which provides a single definition of fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. Prior to SFAS 157, guidance for applying fair value was incorporated into several accounting pronouncements. SFAS 157 emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and sets out a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources (observable inputs) and those based on an entity s own assumptions (unobservable inputs). Under SFAS 157, fair value measurements are disclosed by level within that hierarchy, with the highest priority being quoted prices in active markets. While this statement does not require any new fair value measurements, the application of this statement will change current practice for some fair value measurements.

This statement also nullifies the guidance in footnote 3 of Emerging Issues Task Force (EITF) Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities (EITF 02-3). The guidance in footnote 3 applied for derivative (and other) instruments measured at fair value at initial recognition under SFAS 133. That guidance precluded immediate recognition in earnings of an unrealized gain or loss, measured as the difference between the transaction price and the fair value of the instrument at initial recognition, if the fair value of the instrument was determined using significant unobservable inputs. Under this guidance, an entity could not recognize an unrealized gain or loss at inception of a derivative instrument unless the fair value of that instrument was obtained from a quoted market price in an active market or was otherwise evidenced by comparison to other observable current market transaction or based on a valuation technique incorporating observable market data. SFAS 157 requires that the principles of fair value measurement should be applied for derivatives and other financial instruments at initial recognition and in all subsequent periods. At December 31, 2007, PSEG has a deferred inception loss of $34 million, which is expected to be recognized through Retained Earnings in the first quarter of 2008.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. PSEG adopted this statement effective January 1, 2008. In February 2008, the FASB also issued two FASB Staff Positions (FSPs):

FSP FAS 157-1 to exclude leasing transactions accounted for under SFAS No. 13, Accounting for Leases and its related interpretive pronouncements from SFAS 157 s scope

FSP FAS 157-2 to partially defer the effective date of SFAS 157 for non financial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis.

Both FSPs are expected to simplify PSEG s adoption of SFAS 157 on January 1, 2008.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (SFAS 159)

PSEG, Power and PSE&G

In February 2007, the FASB issued SFAS 159, which permits entities to measure many financial instruments and certain other items at fair value that are not currently required to be measured at fair value. An entity would report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The decision about whether to elect the fair value option is applied instrument by instrument, with a few exceptions; the decision is irrevocable; and it is required to be applied only to entire instruments and not to portions of instruments.

The statement requires disclosures that facilitate comparisons (a) between entities that choose different measurement attributes for similar assets and liabilities and (b) between assets and liabilities in the financial statements of an entity that selects different measurement attributes for similar assets and liabilities.

SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Upon implementation, an entity shall report the effect of the first remeasurement to fair value as a cumulative-effect adjustment to the opening balance of Retained Earnings. Since the provisions of SFAS 159 are applied prospectively, any potential impact will depend on the instruments selected for fair value measurement at the time of implementation. PSEG adopted this statement effective January 1, 2008. However, to date PSEG has not elected any of its assets or liabilities to fair value under this standard.

FASB Staff Position (FSP) FIN 39-1, An amendment of FASB Interpretation No. 39

PSEG and Power

In April 2007, the FASB issued FSP FIN 39-1, An amendment of FASB Interpretation No. 39 (FSP FIN 39-1). This FSP amends FIN 39, Offsetting of Amounts Related to Certain Contracts to permit an entity to offset cash collateral paid or received against fair value amounts recognized for derivative instruments held with the same counterparty under the same master netting arrangement. Currently, PSEG and Power offset derivative contracts under master netting arrangements in accordance with FIN 39 but do not net these balances with cash collateral positions. Under this FSP, PSEG and Power would be required to net cash collateral with the corresponding net derivative balance or elect to show all fair values gross.

FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007 and must be applied retroactively to all financial statements presented, unless it is impracticable to do so. PSEG and Power adopted this FSP effective January 1, 2008. PSEG and Power have established a policy of netting fair value cash collateral receivables and payables with the corresponding net derivative balances and with retroactive adjustments to reflect the adoption of this standard in 2008.

SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141(R)),

PSEG, Power and PSE&G

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS 141(R)), which replaces SFAS 141. SFAS 141(R) will significantly change financial accounting and reporting of business combination transactions. Issuance of SFAS 141(R) marks the FASB s most significant

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

convergence effort with the International Accounting Standards Board (IASB) and move towards fair value accounting. SFAS 141(R) is based on the principle that all the assets acquired and the liabilities assumed in a business combination should be measured at their acquisition date fair values, with limited exceptions. This standard applies to all transactions and events in which an entity obtains control of one or more businesses of the acquiree. The standard also expands the definition of a business. Transactions formerly recorded as an asset acquisition, may qualify as a business combination under SFAS 141(R). It also requires that acquisition-related costs and certain restructuring costs be recognized separately from the business combination.

SFAS No. 141(R) is effective for fiscal years beginning on or after December 15, 2008. Earlier adoption is prohibited. SFAS 141(R) is required to be adopted concurrently with SFAS 160. PSEG, Power and PSE&G will adopt SFAS 141(R) effective January 1, 2009. Accordingly, all business combinations for which the acquisition date is on or after January 1, 2009, will be accounted for under this new guidance.

SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51 (SFAS No. 160)

PSEG, Power and PSE&G

In December 2007, the FASB issued SFAS 160. The new standard will significantly change the financial reporting relationship between a parent and non-controlling interest (i.e. minority interest). SFAS 160 requires all entities to report minority interests in subsidiaries as equity in the consolidated financial statements. Accordingly, the amount of net income attributable to the noncontrolling interest is required to be included in consolidated net income on the face of the income statement. Further, transactions between a parent and noncontrolling interests are treated as equity. However, if a subsidiary is deconsolidated, a parent is required to recognize a gain or loss.

SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. Earlier adoption is prohibited. SFAS 160 will be applied prospectively, except for presentation and disclosure requirements which are required to be applied retrospectively.

The following new accounting standards were adopted by PSEG, Power and PSE&G during 2007.

FIN 48, Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement 109 (FIN 48)

PSEG, Power and PSE&G

In July 2006, the FASB issued FIN 48, which prescribes a model for how a company should recognize, measure, present and disclose in its financial statements uncertain tax positions that the company has taken or expects to take on a tax return. Under FIN 48, the financial statements reflect expected future tax consequences of such positions presuming the tax authorities full knowledge of the position and all relevant facts. FIN 48 permits recognition of the benefit of tax positions only when it is more likely-than-not that the position is sustainable based on the merits of the position. It further limits the amount of tax benefit to be recognized to the largest amount of benefit that is greater than 50% likely of being realized. FIN 48 also requires explicit disclosures about uncertainties in income tax positions, including a detailed roll-forward of unrecognized tax benefits taken that do not qualify for financial statement recognition.

PSEG, Power and Energy Holdings adopted FIN 48 effective January 1, 2007. In general, companies recorded the change in net assets that resulted from the application of FIN 48 as an adjustment to Retained Earnings. However, for PSE&G, because any charges to income arising from the adoption of FIN 48 should be recoverable in future rates, the offset to any incremental PSE&G liability was recorded as a Regulatory Asset rather than Retained Earnings. The following table presents the impact at January 1, 2007 on the Condensed Consolidated Balance Sheets for PSEG and its subsidiaries as a result of implementing FIN 48:

Balance Sheet	Power	PSE&G	Energy Holdings	PSEG Consolidated
(Millions)				
Increase to Long-Term Accrued Taxes				

$

21

$

26

$

355

$

402

Decrease to Accumulated Deferred Income Tax Liability

$

7

$

15

$

246

$

268

Increase to Regulatory Assets

$

$

11

$

$

11

Decrease to Retained Earnings

$

14

$

$

109

$

123

111

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2007, the after-tax expense resulting from the adoption of FIN 48 is summarized as follows:

	Year Ended December 31, 2007
PSEG	$ 27
Power	$ 1
PSE&G	

$

(3

)

Energy Holdings

$

28

For additional information relating to the impacts of FIN 48, see Note 15. Income Taxes.

In May 2007, the FASB issued FASB Staff Position No. FIN 48-1, which provides guidance on how an enterprise should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The adoption of this FSP did not have a material impact on the financial statements of PSEG, PSE&G or Power.

FASB Staff Position (FSP) No. FAS 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 FAS 13-2)

PSEG

In July 2006, the FASB issued FSP FAS 13-2, which addresses how a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction affects the accounting by a lessor for that lease. The FSP amends SFAS No. 13, Accounting for Leases, stating that a change in the timing of the above referenced cash flows must be reviewed at least annually or more frequently, if events or circumstances indicate a change in timing is probable. If a change in timing has occurred, or is projected to occur, the rate of return and the allocation of income to positive investment years must be recalculated from the inception of the lease.

The guidance in this FSP was adopted effective January 1, 2007. The cumulative effect of applying the provisions of this FSP was reported as an adjustment to the beginning balance of Retained Earnings as of the date of adoption. As a result of implementing FSP FAS 13-2, upon adoption PSEG recognized a reduction in Investment in Leveraged Leases of $69 million, a reduction in Deferred Income Taxes of $2 million and a reduction in Retained Earnings of $67 million.

The impact to earnings for PSEG resulting from the adoption of FSP FAS 13-2 for year ended December 31, 2007 was an after-tax decrease of $12 million.

Note 3. Asset Retirement Obligations (AROs)

PSEG, Power and PSE&G

PSEG, Power and PSE&G have recorded various AROs under SFAS No. 143, Accounting for Asset Retirement Obligations (SFAS 143) and FIN 47, Accounting for Conditional Asset Retirement Obligations (FIN 47).

Power

Power s ARO liability primarily relates to the decommissioning of its nuclear power plants. Power maintains an independent external trust to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 13. Nuclear Decommissioning. Power also identified conditional AROs under FIN 47, primarily related to Power s fossil generation units, including liabilities for the removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites, restoration of leased office space to rentable condition upon lease termination, permits and authorizations, the restoration of an area occupied by a reservoir when the reservoir is no longer needed, the demolition of certain plants and the restoration of the sites at which they reside when the plants are no longer in service.

During 2007, Power recorded less than $1 million related to new liabilities under FIN 47.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G

PSE&G has a conditional ARO for legal obligations identified under FIN 47 related to the removal of asbestos and underground storage tanks at certain industrial establishments, removal of wood poles, leases and licenses, and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G did not record an ARO for PSE&G s protected steel and poly based natural gas transmission lines, as management believes that these categories of transmission lines have an indeterminable life.

During 2007, PSE&G recorded less than $1 million related to new liabilities under FIN 47.

PSEG, Power and PSE&G

The changes to the ARO liabilities for PSEG, Power and PSE&G during 2007 are presented in the following table:

(Millions)

PSEG

ARO Liability as of January 1, 2007

$

509

Liabilities Settled

(4

)

Accretion Expense

37

ARO Liability as of December 31, 2007

$

542

Power

ARO Liability as of January 1, 2007

$

287

Liabilities Settled

(1

)

Accretion Expense

23

ARO Liability as of December 31, 2007

$

309

PSE&G

ARO Liability as of January 1, 2007

$

221

Liabilities Settled

(3

)

Accretion Expense(A)

13

ARO Liability as of December 31, 2007

$

231

(A)

Accretion expense is not reflected on PSE&G s Consolidated Statements of Operations as it is deferred and recovered in rate base.

Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments

Discontinued Operations

Power

Lawrenceburg Energy Center (Lawrenceburg)

On May 16, 2007, Power completed the sale of Lawrenceburg, a 1,096-megawatt (MW), gas-fired combined cycle electric generating plant located in Lawrenceburg, Indiana, to AEP Generating Company, a subsidiary of American Electric Power Company, Inc. (AEP).

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.

Lawrenceburg s operating results for the years ended December 31, 2007, 2006 and 2005, which were reclassified to Discontinued Operations, are summarized below:

Years Ended December 31,

2007

2006

2005

(Millions)

Operating Revenues

$

$

41

$

32

Loss Before Income Taxes

$

(13

)

$

(53

)

$

(47

)

Net Loss

$

(8

)

$

(31

)

$

(28

)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The carrying amounts of the assets of Lawrenceburg as of December 31, 2006 are summarized in the following table:

	As of December 31, 2006
	(Millions)
Current Assets	$ 10
Noncurrent Assets	315

Total Assets of Discontinued Operations

$

325

Waterford Generation Facility (Waterford)

In September 2005, Power completed the sale of its electric generation facility located in Waterford, Ohio to a subsidiary of AEP. In 2005, Power recognized a loss on disposal of $178 million, net of tax benefit of $123 million. The proceeds of the sale, together with the anticipated reduction in tax liability, were $320 million and were used to retire debt at Power.

Waterford s operating results for the year ended December 31, 2005, which were reclassified to Discontinued Operations, is summarized below:

Years Ended
December 31,
2005

(Millions)

Operating Revenues

$

18

Loss Before Income Taxes

$

(34

)

Net Loss

$

(20

)

Global

SAESA Group

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. As a result, operating results for the SAESA Group have been reclassified to Discontinued Operations. In conjunction with management s decision 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 No. 23, Accounting for Income Taxes- Special Areas (APB 23).

SAESA Group s operating results for the years ended December 31, 2007, 2006 and 2005, which were reclassified to Discontinued Operations, are summarized below:

Years Ended December 31,

2007

2006

2005

(Millions)

Operating Revenues

$

442

$

341

$

263

Income Before Income Taxes

$

55

$

46

$

43

Net (Loss) Income

$

(34

)

$

57

$

35

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The carrying amounts of SAESA Group s assets as of December 31, 2007 and 2006 are summarized in the following table:

(Millions)	As of December 31, 2007	As of December 31, 2006
Current Assets	$	191

$

136

Noncurrent Assets

971

859

Total Assets of Discontinued Operations

$

1,162

$

995

Current Liabilities.

$

130

$

84

Noncurrent Liabilities

390

203

Total Liabilities of Discontinued Operations

$

520

$

287

Electroandes S.A. (Electroandes)

On September 19, 2007, Global entered into an agreement for the sale of Electroandes, a hydro-electric generation and transmission company in Peru that owns and operates four hydro-generation plants with total capacity of 180 MW and 437 miles of electric transmission lines. The purchaser is a wholly owned subsidiary of Statkraft Norfund Power Invest of Norway.

The sale was completed on October 17, 2007 for a total purchase price of $390 million, including the assumption of approximately $108 million of debt. Net cash proceeds, after taxes of $72 million and including dividends received prior to closing were approximately $220 million, which resulted in an after-tax gain of $48 million recorded in the fourth quarter of 2007.

Operating results for Electroandes have been reclassified to Discontinued Operations. In conjunction with the plan to sell Electroandes, Global recorded a $19 million income tax expense in the second quarter of 2007 related to the discontinuation of applying APB 23, as the income generated by Electroandes is no longer expected to be indefinitely reinvested.

Electroandes operating results for the years ended December 31, 2007, 2006 and 2005, which were reclassified to Discontinued Operations, are summarized below:

Years Ended
December 31,

2007

2006

2005

(Millions)

Operating Revenues

$

41

$

61

$

52

Income Before Income Taxes

$

15

$

22

$

18

Net Income

$

10

$

16

$

14

The carrying amounts of the assets of Electroandes as of December 31, 2006 are summarized in the following table:

	As of December 31, 2006
	(Millions)
Current Assets	$ 25
Noncurrent Assets	

272

Total Assets of Discontinued Operations

$

297

Current Liabilities

$

9

Noncurrent Liabilities

125

Total Liabilities of Discontinued Operations

$

134

Elektrocieplownia Chorzow Elcho Sp. Z o.o. (Elcho) and Elektrownia Skawina SA (Skawina)

On January 31, 2006, Global entered into an agreement with CEZ a.s. to sell its interest in two coal-fired plants in Poland, Elcho and Skawina. The sale was completed on May 29, 2006. Proceeds, net of transaction costs, were $476 million, resulting in a gain of $227 million net of tax expense of $142 million. This gain is

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

included in Discontinued Operations. The 2006 and 2005 operating results for Global s assets in Poland have been reclassified to Discontinued Operations.

Elcho s and Skawina s operating results for the years ended December 31, 2006 and 2005 are summarized below:

Years Ended December 31,

Elcho

Skawina

2007

2006

2005

2007

2006

2005

(Millions)

Operating Revenues

$

$

39

$

106

$

$

44

$

125

(Loss) Income Before Income Taxes

$

$

(3

)

$

17

$

$

2

$

3

Net (Loss) Income

$

$

(2

)

$

16

$

$

1

$

2

Dispositions

Power

In December 2006, Power recorded a pre-tax impairment loss of $44 million to write down four turbines to their estimated realizable value and reclassified them to Assets Held for Sale on Power s Condensed Consolidated Balance Sheet. In April 2007, Power sold the four turbines to a third party and received proceeds of $40 million, which approximated the recorded book value.

Global

Chilquinta Energia S.A. (Chilquinta) and Luz del Sur S.A.A. (LDS)

On December 14, 2007, Global closed on the sales of its 50% ownership interest in the Chilean electric distributor, Chilquinta and its affiliates and its 38% ownership interest in the Peruvian electric distributor, LDS and its affiliates, for $685 million. Net cash proceeds after taxes were approximately $480 million, which resulted in an after-tax loss of $23 million.

Rio Grande Energia S. A. (RGE)

On May 10, 2006, Global entered into an agreement with Companhia Paulista de Force Luz to sell its 32% ownership interest in RGE, a Brazilian electric distribution company. The transaction closed on June 23, 2006 and gross proceeds of $185 million were received. The transaction resulted in a pre-tax write-down of $263 million ($178 million after-tax), primarily related to the devaluation of the Brazilian Real subsequent to Global s acquisition of its interests in RGE in 1997.

Dhofar Power Company S.A.O.C. (Dhofar Power)

In April 2005, Global sold a 35% interest in Dhofar Power through a public offering on the Omani stock exchange as required under its Concession Agreement for the project, reducing Global s ownership in Dhofar Power from 81% to 46%. Net proceeds from the sale were $25 million, resulting in a pre-tax gain of $3 million ($1 million after-tax). As a result, Global s investment in Dhofar Power was accounted for under the equity method following the sale.

On May 15, 2006, Global signed an agreement to sell its remaining 46% interest in Dhofar Power to Oman Technical Partners Ltd. Global closed the sale in November 2006 and received net proceeds after-tax of $31 million, the approximate book value of the investment.

Resources

On December 28, 2005, Resources sold its interest in the Seminole Generation Station Unit 2 (Seminole), a 659 MW coal-fired facility in Palatka, Florida, to Seminole Electric Cooperative Inc. for $286 million, resulting in a pre-tax gain of $71 million ($43 million after-tax).

Resources was the equity investor in a Boeing B767 leased to United Airlines (UAL). In December 2002, UAL filed for Chapter 11 bankruptcy protection. In 2005, Resources received a notice from the Trustee under the UAL lease that the lenders had terminated the lease and repossessed the aircraft. Upon receipt of

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

this notice, Resources recorded a $21 million pre-tax ($15 million after-tax) charge to write off the carrying value of this investment.

Resources was also the equity investor in two operating leases with Northwest Airlines (Northwest) B 757-200 and Delta Airlines (Delta) B 737-200. On September 14, 2005 both Northwest and Delta filed for protection under Chapter 11 of the U.S. Bankruptcy Code. In 2004 and 2005, Resources successfully restructured the leases and converted the Delta and Northwest leases from leveraged leases to operating leases. The Delta aircraft was sold in January 2006, generating a small gain for Resources.

Acquisitions

Global

Bioenergie S.p.A. (Bioenergie)

In May 2006, Global forgave the guarantees of its partner in the Bioenergie investment of certain loans Global had made to Bioenergie and converted such loans totaling $38 million into additional equity in Bioenergie, thereby increasing its ownership interest from 50% to 85% and giving Global voting control of the project. As a result, PSEG began consolidating this investment in May 2006 and reclassified the investment balance to Property, Plant and Equipment of approximately $62 million, Long-Term Investments of approximately $13 million, Capital Lease Obligations of approximately $40 million and certain other assets and liabilities on PSEG s Consolidated Balance Sheet. PSEG recorded certain purchase accounting adjustments to reflect the plant, contracts and investment in Biomasse Italia S.p.A. at fair value.

Impairments

Global

Venezuela

PSEG has indirect ownership interests in two generating facilities in Maracay and Cagua, Venezuela that have a total capacity of 120 MW. The projects are owned and operated by Turboven Company Inc. (Turboven), an entity which is jointly-owned by Global (50%) and Corporacion Industrial de Energia (CIE). Global also has a 9% indirect interest in Turbogeneradores de Maracay through a partnership with CIE.

During Global s 2006 year-end review of its investments, management concluded that due to the current political situation in Venezuela, it was probable that Global would not be able to recover all of its investment in its Venezuelan operations. Therefore, Global recorded an impairment loss of $4 million, after-tax, to write down these investments in the fourth quarter of 2006.

In January 2007, the Venezuelan government announced its intention to nationalize certain sectors of Venezuelan industry and commerce, including certain foreign-owned energy and communications companies. In a subsequent press release, Turboven was named as one of the companies that Venezuela intended to nationalize. Since these announcements, Venezuela has proceeded to nationalize certain companies. Global has entered into valuation discussions with the government of Venezuela as part of the nationalization efforts, which are ongoing. Based upon a review of the circumstances in the third quarter 2007, an additional impairment charge of $7 million, after tax, was recorded in September 2007, based on Global s estimated market valuation of the project.

India

In December 2007, Global recorded an impairment loss of $2 million, after-tax, on Power Generating Company Limited (PPN) based on Global s estimated market valuation of the project.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 5. Regulatory Matters

Regulatory Assets and Liabilities

PSE&G

PSE&G prepares its financial statements in accordance with the provisions of SFAS 71. A regulated utility is required to defer the recognition of costs (a regulatory asset) or the recognition of obligations (a regulatory liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs, which will be amortized over various future periods. These costs are deferred based on rate orders issued by the BPU or the FERC or PSE&G s experience with prior rate cases. All of PSE&G s regulatory assets and liabilities at December 31, 2007 and 2006 are supported by written rate orders, either explicitly or implicitly through the BPU s treatment of various cost items. Regulatory assets are subject to prudence reviews and can be disallowed in the future by regulatory authorities. PSE&G believes that all of its regulatory assets are probable of recovery. To the extent that collection of any regulatory assets or payments of regulatory liabilities is no longer probable, the amounts would be charged or credited to income.

PSE&G had the following regulatory assets and liabilities on the Consolidated Balance Sheets:

As of December 31,

Recovery/Refund Period

2007

2006

(Millions)

Regulatory Assets

Stranded Costs To Be Recovered

$

2,772

$

3,059

Through December 2015(1)(2)

Manufactured Gas Plant (MGP) Remediation Costs

639

414

Various(2)

Pension and Other Postretirement

468

671

Various

Deferred Income Taxes

420

412

Various

Societal Benefits Charges (SBC)

151

279

Various(2)

New Jersey Clean Energy Program

149

253

To be determined (2)

Gas Contract Mark-to-Market

105

187

Various(1)

Other Postretirement Benefits (OPEB) Costs

96

116

Through December 2012(2)

Unamortized Loss on Reacquired Debt and Debt Expense

80

85

Over remaining debt life(1)

Conditional Asset Retirement Obligation

80

68

Various

Repair Allowance Taxes

54

62

Through August 2013(1)(2)

Uncertain Tax Positions

38

Various

Regulatory Restructuring Costs

27

31

Through August 2013(1)(2)

Gas Margin Adjustment Clause

25

14

To be determined(2)

Plant and Regulatory Study Costs

15

16

Through December 2021(2)

Incurred But Not Reported Claim Reserve

14

Various

Asbestos Abatement

9

10

Through 2020(2)

Non-Utility Generation Charge (NGC)

9

Through July 2008(2)

Other

14

17

Various

Total Regulatory Assets

$

5,165

$

5,694

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of
December 31,

Recovery/Refund Period

2007

2006

(Millions)

Regulatory Liabilities

Cost of Removal

$

274

$

279

Various

Overrecovered Gas Costs

54

96

Through October 2008 (1)(2)

Excess Cost of Removal

51

64

Through November 2011(1)(2)

Overrecovered Electric Costs

28

198

To be determined(1)(2)

Other

12

9

Various(1)

Total Regulatory Liabilities

$

419

$

646

(1)

Recovered/Refunded with interest.

(2)

Recoverable/Refundable per specific rate order.

All regulatory assets and liabilities are excluded from PSE&G s rate base unless otherwise noted. The descriptions below define certain regulatory items.

Stranded Costs To Be Recovered: This reflects deferred costs, which are being recovered through the securitization transition charges authorized by the BPU in irrevocable financing orders and being collected by PSE&G, as servicer on behalf of Transition Funding and Transition Funding II, respectively. Funds collected are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs and taxes.

MGP Remediation Costs: Represents the low end of the range for the remaining environmental investigation and remediation program costs that are probable of recovery in future rates. Once these costs are incurred they are recovered through the Remediation Adjustment Charge clause in the SBC.

Pension and Other Post Retirement: Pursuant to the adoption of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (SFAS 158), PSE&G recorded the unrecognized costs for defined benefit pension and OPEB plans on the balance sheet as a regulatory asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs will be amortized and recovered in future rates.

Deferred Income Taxes: This amount represents the portion of deferred income taxes that will be recovered through future rates, based upon established regulatory practices, which permit the recovery of current taxes. Accordingly, this regulatory asset is offset by a deferred tax liability and is expected to be recovered, without interest, over the period the underlying book-tax timing differences reverse and become current taxes.

SBC: The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act (Competition Act), includes costs related to PSE&G s electric and gas business as follows: 1) the Universal Service Fund; 2) Energy Efficiency and Renewable Energy Programs. 3) Social Programs (electric only) which include electric bad debt expense; and 4) the Remediation Adjustment Clause for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.

New Jersey Clean Energy Program: The BPU approved future funding requirement for Energy Efficiency and Renewable Energy Programs programs through 2008.

Gas Contract Mark-to-Market: The fair value of gas hedge contracts and gas cogeneration supply contracts. This asset is offset by a derivative liability and an intercompany payable on the Balance Sheet.

OPEB Costs: Includes costs associated with the adoption of SFAS No. 106, Employers Accounting for Benefits Other Than Pensions which were deferred in accordance with EITF Issue No. 92-12, Accounting for OPEB Costs by Rate Regulated Enterprises.

Unamortized Loss on Reacquired Debt and Debt Expense: Represents losses on reacquired long-term debt, which are recovered through rates over the remaining life of the debt.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Conditional Asset Retirement Obligation: These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.

Uncertain Tax Positions: The amount recorded for uncertain tax positions under FIN 48 which would have been expensed or charged to Retained Earnings upon adoption but will be recoverable in future rates.

Repair AllowanceTaxes: This represents tax, interest and carrying charges relating to disallowed tax deductions for repair allowance as authorized by the BPU with recovery over 10 years effective August 1, 2003.

Regulatory Restructuring Costs: These are costs related to the restructuring of the energy industry in New Jersey through the Competition Act and include such items as the system design work necessary to transition PSE&G to a transmission and distribution only company, as well as costs incurred to transfer and establish the generation function as a separate corporate entity with recovery over 10 years beginning August 1, 2003.

Gas Margin Adjustment Clause: PSE&G defers the margin differential received from Transportation Gas Service Non-Firm Customers versus bill credits provided to Basic Gas Supply Service (BGSS)-Firm customers.

Plant and Regulatory Study Costs: These are costs incurred by PSE&G and required by the BPU which are related to current and future operations, including safety, planning, management and construction.

Incurred But Not Reported Claim Reserve: Represents reserves for worker s compensation and injuries and damages that exceed the amounts recognized in rates on a settlement accounting basis.

NGC: Represents the difference between the cost of non-utility generation and the amounts realized from selling that energy at market rates through PJM. The BPU instructed PSE&G to transfer the remaining $150 million debit balance for the Market Transition Charge (MTC) from the SBC to the NGC in March 2007.

Asbestos Abatement: Represents costs incurred to remove and dispose of asbestos insulation at PSE&G s fossil generating stations. Per a BPU order dated December 9, 1992, these costs are treated as Cost of Removal for ratemaking purposes.

Other Regulatory Assets: This includes the following: 1) Energy Information Control Network program costs; 2) Transition Funding s interest rate swap (offset by a derivative liability); and 3) deferred costs for the new customer information system.

Cost of Removal: PSE&G accrues and collects for Cost of Removal in rates. Pursuant to the adoption of SFAS 143, the liability for Cost of Removal was reclassified as a regulatory liability. This liability is reduced as removal costs are incurred. Cost of removal is a reduction to the rate base.

Overrecovered Gas Costs: These costs represent the over recovered amounts associated with BGSS, as approved by the BPU.

Excess Cost of Removal: The BPU directed PSE&G to refund $66 million of excess gas cost of removal accruals over a 5 year period ending November 2011.

Overrecovered Electric Energy Costs: These costs represent the over recovered amounts associated with Basic Generation Service (BGS), as approved by the BPU. The 2006 balance includes $180 million from the NTC, now the NGC, as referred to above.

Other Regulatory Liabilities: This includes the following: 1) a retail adder included in the BGS charges; 2) amounts collected from customers in order for Transition Funding to obtain a AAA rating on its transition bonds; 3) third party billing discounts related to the Competition Act; and (4) the FAS 158 liability associated with the non-qualified pension plan.

Note 6. Earnings Per Share (EPS)

PSEG

Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG s stock compensation plans, upon payment of performance units or restricted stock units and upon conversion of Participating Units. The following table shows the effect of

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

these stock options, restricted stock awards, performance units, restricted stock units and Participating Units on the weighted average number of shares outstanding used in calculating diluted EPS:

Years Ended December 31,

2007

2006

2005

Basic

Diluted

Basic

Diluted

Basic

Diluted

EPS Numerator:

Earnings (Millions)

Continuing Operations

$

1,319

$

1,319

$

679

$

679

$

837

$

837

Discontinued Operations

16

16

60

60

(159

)

(159

)

Cumulative Effect of a Change in Accounting Principle

(17

)

(17

)

Net Income

$

1,335

$

1,335

$

739

$

739

$

661

$

661

EPS Denominator (Thousands):

Weighted Average Common Shares Outstanding

507,560

507,560

503,356

503,356

480,594

480,594

Effect of Stock Options

678

1,090

1,942

Effect of Stock Performance Units

560

182

174

Effect of Restricted Stock

12

Effect of Restricted Stock Units

3

Effect of Participating Units

6,102

Total Shares

507,560

508,813

503,356

504,628

480,594

488,812

EPS:

Continuing Operations

$

2.60

$

2.59

$

1.35

$

1.34

1.74

$

1.71

Discontinued Operations

0.03

0.03

0.12

0.12

(0.33

)

(0.33

)

Cumulative Effect of a Change in Accounting Principle

(0.03

)

(0.03

)

Net Income

$

2.63

$

2.62

$

1.47

$

1.46

$

1.38

$

1.35

No stock options or Participating Units had an antidilutive effect for the years ended December 31, 2007, 2006 or 2005.

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 approved a two-for-one stock split of PSEG s outstanding shares of common stock to be effected in the form of a stock dividend. 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7. Goodwill and Other Intangibles

PSEG and Power

As of December 31, 2007 and 2006, Power had goodwill of $16 million related to the Bethlehem Energy Center. Power conducted an annual review for goodwill impairment as of October 31, 2007 and concluded that goodwill was not impaired. No events occurred subsequent to that date which would require a further review of goodwill for impairment. During 2007, goodwill related to SAESA which was $418 million and $390 million as of December 31, 2007 and 2006, respectively was reclassified to assets of discontinued operations.

Also during 2007, Global sold its investments in Electroandes, Chilquinta and LDS. As of December 31, 2006, Global s goodwill in Electroandes and pro-rata share of goodwill in Chilquinta and LDS was $133 million, $193 million and $55 million, respectively.

In addition to goodwill, as of December 31, 2007 and 2006, PSEG had recorded intangible assets of $48 million and $46 million, respectively. These included $35 million for both years of emissions allowances at Power and $13 million and $11 million largely related to the fair value of a power purchase agreement resulting from a purchase price allocation at Bioenergie as of December 31, 2007 and 2006, respectively. Power emissions allowances are expensed as used or sold, which amounted to $2 million, $3 million and $5 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Note 8. Long-Term Investments

PSEG, Power and PSE&G

PSEG, Power and PSE&G had the following Long-Term Investments as of December 31, 2007 and 2006:

As of December 31,

2007

2006

(Millions)

Leveraged Leases

$

2,826

$

2,810

Partnerships and Corporate Joint Ventures(A)

261

883

Life Insurance and Supplemental Benefits (PSE&G)

146

142

Investment in Capital Trusts

20

Other Investments

13

13

Total Long-Term Investments

$

3,246

$

3,868

(A)

Accounted for under the equity method of accounting. Includes $14 million and $16 million as of December 31, 2007 and 2006, respectively, related to Power s 23% ownership interest in Keystone Fuels Corporation and Conemaugh Fuels Corporation.

Leveraged Leases

PSEG s net investment, through Resources, in leveraged leases was comprised of the following elements:

As of December 31,

2007

2006

(Millions)

Lease rents receivable (net of non-recourse debt)

$

2,890

$

2,918

Estimated residual value of leased assets

1,010

1,012

3,900

3,930

Unearned and deferred income

(1,074

)

(1,120

)

Total investments in leveraged leases

2,826

2,810

Deferred tax liabilities

(2,045

)

(1,886

)

Net investment in leveraged leases

$

781

$

924

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The pre-tax income and income tax effects related to investments in leveraged leases were as follows:

Years Ended December 31,	**2007**	**2006**	**2005**
(Millions)			
Pre-tax income of leveraged leases	$		

114

$

134

$

161

Income tax effect on pre-tax income of leveraged leases

$

36

$

41

$

64

Amortization of investment tax credits of leveraged leases

$

(1

)

$

(1

)

$

(1

)

The $23 million decrease in income tax effect on pre-tax income of leveraged leases in 2006 as compared to 2005, was primarily due to the absence of the tax expense resulting from the sale of Resources interest in Seminole in 2005. For additional information regarding the sale of Seminole, see Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments.

Investments in and Advances to Affiliates

Investments in net assets of affiliated companies accounted for under the equity method of accounting by Global amounted to $208 million and $818 million as of December 31, 2007 and 2006, respectively. During the three years ended December 31, 2007, 2006 and 2005, the amount of dividends from these investments was $108 million, $74 million and $70 million, respectively. Global s share of income and cash flow distribution percentages ranged from 40% to 60% as of December 31, 2007.

As of December 31, 2007, Global s recorded investment in equity method subsidiaries was $208 million as compared to $240 million of underlying equity in net assets of such investments.

PSEG had the following equity method investments as of December 31, 2007:

Name

Location

%
Owned

Kalaeloa

HI

50

%

GWF

Bay Area I

CA

50

%

Bay Area II

CA

50

%

Bay Area III

CA

50

%

Bay Area IV

CA

50

%

Bay Area V

CA

50

%

Hanford L.P

CA

50

%

GWF Energy

Hanford-Peaker Plant

CA

60

%

Henrietta-Peaker Plant

CA

60

%

Bridgewater

NH

40

%

Turboven

Maracay

Venezuela

50

%

Cagua

Venezuela

50

%

Bioenergie

Italy

43

%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Summarized results of operations and financial position of affiliates in which PSEG applied the equity method of accounting are presented below:

Foreign

Domestic

Total

(Millions)

December 31, 2007

Statement of Operations Information

Revenue

$

134

$

386

$

520

Gross Profit

$

73

$

147

$

220

Net Income

$

$

86

$

86

Balance Sheet Information

Assets:

Current Assets

$

69

$

108

$

177

Property, Plant and Equipment

190

537

727

Goodwill

50

50

Other Noncurrent Assets

19

25

44

Total Assets

$

278

$

720

$

998

Liabilities:

Current Liabilities

$

38

$

78

$

116

Debt*

134

217

351

Other Noncurrent Liabilities

66

66

Total Liabilities

172

361

533

Equity

106

359

465

Total Liabilities and Equity

$

278

$

720

$

998

December 31, 2006

Statement of Operations Information

Revenue

$

858

$

378

$

1,236

Gross Profit

$

345

$

154

$

499

Minority Interest

$

15

$

$

15

Net Income

$

107

$

86

$

193

Balance Sheet Information

Assets:

Current Assets

$

314

$

100

$

414

Property, Plant and Equipment

1,072

555

1,627

Goodwill

497

49

546

Other Noncurrent Assets

187

32

219

Total Assets

$

2,070

$

736

$

2,806

Liabilities:

Current Liabilities

$

186

$

63

$

249

Debt*

675

203

878

Other Noncurrent Liabilities

143

60

203

Minority Interest

70

70

Total Liabilities

1,074

326

1,400

Equity

996

410

1,406

Total Liabilities and Equity

$

2,070

$

736

$

2,806

December 31, 2005

Statement of Operations Information

Revenue

$

1,773

$

366

$

2,139

Gross Profit

$

513

$

133

$

646

Minority Interest

$

14

$

$

14

Net Income

$

170

$

78

$

248

---

*

Debt is non-recourse to PSEG, Energy Holdings and Global.

The differences in the results of operations and the financial position as of and for the year ended December 31, 2007, as compared to 2006, were due to PSEG s sale of its 50% interest in Chilquinta, its 38% stake in LDS and its 34.5% interest in Tracy Biomass as well as EGDC s sale of their Largo property. See

---

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments for further details of these transactions.

PSEG also has investments in certain companies in which it does not have the ability to exercise significant influence. Such investments are accounted for under the cost method. As of December 31, 2007 and 2006, the carrying value of these investments aggregated $31 million and $37 million, respectively. PSEG periodically reviews these cost method investments for impairment and adjusts the values of these investments accordingly.

Note 9. Schedule of Consolidated Capital Stock and Other Securities

Outstanding Shares As of December 31, 2007

Redemption Price Per Share as of December 31, 2007

Book Value
As of
December 31,

2007

2006

(Millions)

PSEG Common Stock (no par value)(A)

Authorized 1,000,000,000 shares; (outstanding as of December 31, 2006, 505,290,816 shares)

508,523,004

$

4,254

$

4,145

PSE&G Cumulative Preferred Stock(B) without Mandatory Redemption(C) $100 par value series

4.08%

146,221

$

103.00

$

15

$

15

4.18%

116,958

$

103.00

12

12

4.30%

149,478

$

102.75

15

15

5.05%

104,002

$

103.00

10

10

5.28%

117,864

$

103.00

12

12

6.92%

160,711

$

102.43

16

16

Total Preferred Stock without Mandatory Redemption

795,234

$

80

$

80

(A)

For the years ended December 31, 2007, 2006 and 2005, PSEG issued approximately 0.8 million, 2.1 million, and 2.4 million shares, respectively, for $35 million, $67 million and $72 million, respectively, under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) and the Employee Stock Purchase Plan (ESPP). Total authorized and unissued shares of common stock available for issuance through PSEG s DRASPP, ESPP and various employee benefit plans amounted to approximately 7.0 million shares as of December 31, 2007.

(B)

As of December 31, 2007, there was an aggregate of approximately 6.7 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption. If dividends upon any shares of Preferred Stock are in arrears for four consecutive quarters, holders receive voting rights for the election of a majority of PSE&G s Board of Directors and continue until all accumulated and unpaid dividends thereon have been paid, whereupon all such voting rights cease. There are no arrearages in cumulative preferred stock and hence currently no voting rights for preferred shares. No preferred stock agreement contains any liquidation preferences in excess of par values or any deemed liquidation events.

(C)

As of each December 31, 2007 and 2006, the annual dividend requirement and the embedded dividend rate for PSE&G s Preferred Stock without Mandatory Redemption was approximately $4 million and 5.03%, respectively.

Fair Value of Preferred Securities

The estimated fair value of PSE&G s Cumulative Preferred Stock was $68 million and $72 million as of December 31, 2007 and 2006, respectively. The estimated fair value was determined using market quotations.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 10. Schedule of Consolidated Debt

Long-Term Debt

Maturity

As of December 31,

2007

2006

(Millions)

PSEG

Senior Note 6.89%(A)

2007 2009

$

98

$

147

Senior Note Libor +.375%(B)

2008

375

Senior Note 4.66%

2009

200

200

Debt Supporting Trust Preferred Securities(C)

2007 2032

660

Other(D)

(7

)

Principal Amount Outstanding

298

1,375

Amounts Due Within One Year(E)

(49

)

(522

)

Total Long-Term Debt of PSEG (Parent)

$

249

$

853

Power

Senior Notes:

3.75%

2009

$

250

$

250

7.75%

2011

800

800

6.95%

2012

600

600

5.00%

2014

250

250

5.50%

2015

300

300

8.625%

2031

500

500

Total Senior Notes

2,700

2,700

Pollution Control Notes:

5.00%

2012

66

66

5.50%

2020

14

14

5.85%

2027

19

19

5.75%

2031

25

25

5.75%(F)

2037

40

4.00%(G)

2042

44

Total Pollution Control Notes

208

124

Net Unamortized Discount

(6

)

(6

)

Total Long-Term Debt of Power

$

2,902

$

2,818

PSE&G

First and Refunding Mortgage Bonds:

6.25%(H)

2007

$

$

113

6.75%

2016

171

171

6.45%

2019

5

5

9.25%

2021

134

134

6.38%

2023

157

157

5.20%

2025

23

23

4.25%Auction Rate(I)

2028

64

64

4.25%Auction Rate(I)

2029

93

93

5.00%Auction Rate(I)

2030

88

88

4.25%Auction Rate(I)

2031

104

104

5.45%

2032

50

50

6.40%

2032

100

100

5.05%Auction Rate(I)

2033

50

50

4.25%Auction Rate(I)

2033

50

50

4.25%Auction Rate(I)

2033

45

45

8.00%

2037

7

7

5.00%

2037

8

8

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Maturity

As of December 31,

2007

2006

(Millions)

Medium-Term Notes:

4.00%

2008

$

250

$

250

8.16%

2009

16

16

8.10%

2009

44

44

5.125%

2012

300

300

5.00%

2013

150

150

5.375%

2013

300

300

5.00%

2014

250

250

7.04%

2020

9

9

7.18%

2023

5

5

7.15%

2023

34

34

5.25%

2035

250

250

5.70%

2036

250

250

5.80%(J)

2037

350

Principal Amount Outstanding

3,357

3,120

Amounts Due Within One Year(E)

(250

)

(113

)

Net Unamortized Discount

(5

)

(4

)

Total Long-Term Debt of PSE&G (excluding Transition Funding and Transition Funding II)

$

3,102

$

3,003

Transition Funding (PSE&G)

Securitization Bonds(K):

6.29%

2009

$

251

$

412

6.45%

2011

328

328

6.61%

2013

454

454

6.75%

2014

220

220

6.89%

2015

370

370

Principal Amount Outstanding

1,623

1,784

Amounts Due Within One Year(E)

(169

)

(161

)

Total Securitization Debt of Transition Funding I

$

1,454

$

1,623

Transition Funding II (PSE&G)

Securitization Bonds(K):

4.18%

2007 2008

$

8

$

17

4.34%

2008 2012

35

35

4.49%

2013

20

20

4.57%

2015

23

23

Principal Amount Outstanding

86

95

Amounts Due Within One Year(E)

(10

)

(10

)

Total Securitization Debt of Transition Funding II

$

76

$

85

Total Long-Term Debt of PSE&G

$

4,632

$

4,711

Energy Holdings (Parent)

Senior Notes:

8.625%(L)

2008

$

207

$

207

10.00%(M)

2009

400

400

8.50%(N)

2011

530

544

Principal Amount Outstanding

1,137

1,151

Amounts Due Within One Year(E)

(607

)

Net Unamortized Discount

(2

)

Total Long-Term Debt of Energy Holdings (Parent)

$

530

$

1,149

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Maturity

As of December 31,

2007

2006

(Millions)

Global (Energy Holdings)(O)

Non-Recourse Debt:

PSEG Texas (Odessa) Libor +2.25% 3.25%(P)

2007 2009

$

177

$

194

PSEG Texas (Guadalupe) Libor +1.875% 2.00%(Q)

2007 2009

153

181

Chilquinta 5.58% 6.62%(R)

2008 2011

162

Bioenergie

2026

3

3

Principal Amount Outstanding

333

540

Amounts Due Within One Year(E)

(32

)

(25

)

Total Long-Term Debt of Global

$

301

$

515

Resources (Energy Holdings)(O)

4.75% 8.75% Non-Recourse Bank Loan

2007 2016

$

36

$

40

Amounts Due Within One Year(E)

(3

)

(3

)

Total Long-Term Debt of Resources

$

33

$

37

EGDC (Energy Holdings)(O)

8.27% Non-Recourse Mortgage

2007 2013

$

17

$

19

Amounts Due Within One Year(E)

(2

)

(2

)

Total Long-Term Debt of EGDC

$

15

$

17

Total Long-Term Debt of Energy Holdings

$

879

$

1,718

Total PSEG Consolidated Long-Term Debt

$

8,662

$

10,100

(A)

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

(B)

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

(C)

In December 2007, PSEG called for redemption $186 million of Subordinated Debentures underlying $180 million of PSEG Funding Trust II, Trust Preferred Securities due 2032 at 100% of the principal amount. These debentures were redeemed in December 2007. In November 2007, PSEG redeemed $474 million of Subordinated Debentures underlying $460 million of PSEG Funding Trust I, Participating Equity Preferred Securities. PSEG recorded interest expense of $38 million, $43 million and $80 million for the years ended December 31, 2007, 2006 and 2005, respectively, related to this debt.

(D)

Represents fair value of interest rate swaps. The balance as of December 31, 2007 was less than $1 million.

(E)

The aggregate principal amounts of maturities for each of the five years following December 31, 2007 are as follows:

Year

PSEG

Power

PSE&G

Energy Holdings

Total

PSE&G

Transition Funding

Transition Funding II

Energy Holdings

Global

Resources

EGDC

(Millions)

2008

$

49

$

$

250

$

169

$

10

$

607

$

32

$

3

$

2

$

1,122

2009

249

250

60

178

10

298

4

3

1,052

2010

186

11

20

3

220

2011

800

195

11

530

1

3

1,540

2012

666

300

204

11

3

1,184

$

298

$

1,716

$

610

$

932

$

53

$

1,137

$

330

$

28

$

14

$

5,118

(F)

In November 2007, Power issued $40 million of 5.75% Pollution Control Bonds due 2037.

(G)

In December 2007, Power issued $44 million of 4.00% Pollution Control Bonds due 2042.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(H)

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

(I)

Auction rates are variable. Reflects rates as of December 31, 2007. These pollution control notes ($494 total principal amount) 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 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 in interest rate modes and to hold them until they can be remarketed or refinanced, possibly later in 2008.

(J)

In May 2007, PSE&G issued $350 million of 5.80% Secured Medium-Term Series E Notes due 2037.

(K)

During 2007, Transition Funding and Transition Funding II repaid $161 million and $9 million, respectively, of their Transition Bonds.

(L)

In February 2008, Energy Holdings repaid at maturity $207 million of its 8.625% Senior Notes.

(M)

In December 2007, Energy Holdings called for redemption all of the outstanding $400 million of 10% Senior Notes due 2009. The Senior Notes were redeemed in January 2008.

(N)

In December 2007, Energy Holdings repurchased $14 million of the remaining $544 million of the outstanding 8.50% Senior Notes due 2011.

(O)

Non-recourse financing transactions consist of loans from banks and other lenders that are typically secured by project assets and cash flows and generally impose no material obligation on the parent- level investor to repay any debt incurred by the project borrower. The consequences of permitting a project-level default include the potential for loss of any invested equity by the parent. However, in some cases, certain obligations relating to the investment being financed, including additional equity commitments, may be guaranteed by Global and/or Energy Holdings for their respective subsidiaries. PSEG does not provide guarantees or credit support to Energy Holdings or its subsidiaries.

During 2007, Energy Holdings subsidiaries repaid $51 million of non-recourse debt, including $45 million related to PSEG Texas, $4 million to Resources and $2 million to EGDC.

(P)

In February 2006, the maturity of the debt was extended to December 31, 2009. On September 29, 2006, 80% of the scheduled outstanding principal became subject to an interest rate swap that converted floating rate Libor interest to a fixed rate of 5.4275% through December 31, 2009. On December 31, 2007, the Libor rate on the unswapped portion of the debt was 4.875% and the interest spread was 2.75%.

(Q)

In April 2006, 80% of the scheduled outstanding principal became subject to interest rate swaps that converted floating rate Libor to a weighted average fixed rate of 4.518%. On December 31, 2007, the Libor rate on the unswapped portion of the debt was 4.875% and the interest spread was 1.875%.

(R)

Chilquinta was sold in December 2007.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Short-Term Liquidity

PSEG, Power and PSE&G

As of December 31, 2007, PSEG, Power and PSE&G had the following 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/
Letters of Credit

$

1

(B)

$

999

Uncommitted Bilateral Agreement

N/A

N/A

Funding

$

$

N/A

Power:

5-year Credit Facility(A)

Dec 2012

$

1,600

Funding/
Letters of Credit

$

140

(B)

$

1,460

Bilateral Credit Facility

March 2010

$

100

Funding/
Letters of Credit

$

56

(B)

$

44

Bilateral Credit Facility

March 2008

$

200

Funding/
Letters of Credit

$

28

(B)

$

172

PSE&G:

5-year Credit Facility(A)

June 2012

$

600

CP Support/
Funding/
Letters of Credit

$

55

$

545

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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of December 31, 2007 and 2006, respectively.

December 31, 2007

December 31, 2006

Carrying Amount

Fair Value

Carrying Amount

Fair Value

(Millions)

Long-Term Debt:

PSEG.

$

298

$

299

$

1,375

$

1,369

Power

2,902

3,106

2,818

3,045

PSE&G

3,353

3,370

3,116

3,145

Transition Funding (PSE&G)

1,623

1,792

1,784

1,907

Transition Funding II (PSE&G)

86

87

95

93

Energy Holdings:

Senior Notes

1,137

1,204

1,149

1,232

Project Level, Non-Recourse Debt

386

387

599

606

$

9,785

$

10,245

$

10,936

$

11,397

Because their maturities are less than one year, fair values approximate carrying amounts for cash and cash equivalents, short-term debt and accounts payable. For additional information related to interest rate derivatives, see Note 11. Financial Risk Management Activities.

Note 11. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, foreign currency exchange rates, interest rates and equity prices that could affect their results of operations and financial conditions. PSEG, Power and PSE&G manage exposure to these market risks through their regular operating and financing activities and, when deemed appropriate, hedge these risks through the use of derivative financial instruments. PSEG, Power and PSE&G use the term hedge to mean a strategy designed to manage risks of volatility in prices or rate movements on certain assets, liabilities or anticipated transactions and by creating a relationship in which gains or losses on derivative instruments are expected to counterbalance the gains or losses on the assets, liabilities or anticipated transactions exposed to such market risks. Each of PSEG, Power and PSE&G uses derivative instruments as risk management tools consistent with its respective business plan and prudent business practices.

Derivative Instruments and Hedging Activities

Energy Contracts

Power

Power actively trades energy and energy-related products, including electricity, natural gas, electric capacity, firm transmission rights (FTRs), coal, oil and emission allowances in the spot, forward and futures markets, primarily in PJM, but also in the surrounding region, which extends from Maine to the Carolinas and the Atlantic Coast to Indiana, and natural gas in the producing region.

Power maintains a strategy of entering into positions to optimize the value of its portfolio and reduce earnings volatility of generation assets, gas supply contracts and its electric and gas supply obligations. Power engages in physical and financial transactions in the electricity wholesale markets and executes an overall risk management strategy seeking to mitigate the effects of adverse movements in the fuel and electricity markets. These contracts also involve financial transactions including swaps, options and futures. There have been significant increases in commodity prices over the last year. The resultant changes in market values for energy and related contracts that qualify for hedge accounting have resulted in significant increases to Accumulated Other Comprehensive Loss. For additional information, see Note 12. Commitments and Contingent Liabilities. Power marks its derivative energy contracts to market in accordance with SFAS 133, with changes in fair value charged to the Consolidated Statements of Operations. Wherever possible, fair

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

values for these contracts are obtained from quoted market sources. For contracts where no quoted market exists, modeling techniques are employed using assumptions reflective of current market rates, yield curves and forward prices, as applicable, to interpolate certain prices. The effect of using such modeling techniques is not material to Power s financial results.

Commodity Contracts

Power

The availability and price of energy commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power manages its risk of fluctuations of energy price and availability through derivative instruments, such as forward purchase or sale contracts, swaps, options, futures and FTRs.

Cash Flow Hedges

Power uses forward sale and purchase contracts, swaps and FTR contracts to hedge forecasted energy sales from its generation stations and to hedge related load obligations. Power also enters into swaps and futures transactions to hedge the price of fuel to meet its fuel purchase requirements. These derivative transactions are designated and effective as cash flow hedges under SFAS 133. As of December 31, 2007, the fair value of these hedges was $(427) million. These hedges, along with realized losses on hedges of $(4) million retained in Accumulated Other Comprehensive Loss, resulted in a $(250) million after-tax impact on Accumulated Other Comprehensive Loss. As of December 31, 2006, the fair value of these hedges was $(166) million. These hedges, along with realized losses on hedges of $(19) million retained in Accumulated Other Comprehensive Loss, resulted in a $(108) million after-tax impact on Accumulated Other Comprehensive Loss. During 2008, $147 million (after-tax) of net unrealized and realized losses on these commodity derivatives is expected to be reclassified to earnings. $66 million of after-tax unrealized losses on these commodity derivatives in Accumulated Other Comprehensive Loss is expected to be reclassified to earnings for the year ending December 31, 2009. Ineffectiveness associated with these hedges, as defined in SFAS 133, was $(8) million at December 31, 2007. The expiration date of the longest dated cash flow hedge is in 2011.

Other Derivatives

Power also enters into certain other contracts that are derivatives, but do not qualify for cash flow hedge accounting under SFAS 133. Most of these contracts are used for fuel purchases for generation requirements and for electricity purchases for contractual sales obligations. Therefore, the changes in fair market value of these derivative contracts are recorded in Energy Costs or Operating Revenues, as appropriate, on the Consolidated Statements of Operations. The net fair value of these instruments was $(10) million and $1 million as of December 31, 2007 and 2006, respectively.

PSEG Texas

Other Derivatives

PSEG Texas enters into electricity forward and capacity sale contracts to sell its 2,000 MW capacity for portions of the current calendar year, with the balance sold into the daily spot market. PSEG Texas also enters into gas purchase contracts to specifically match the generation requirements to support the electricity forward sales contracts. Although these contracts fix the amount of revenue, fuel costs and cash flows, and thereby provide financial stability to PSEG Texas, these contracts are, based on their terms, derivatives that do not meet the specific accounting criteria in SFAS

133 to qualify for the normal purchases and normal sales exception, or to be designated as a hedge for accounting purposes. As a result, these contracts must be recorded at fair value. The net fair value of the open positions was $63 million and $38 million as of December 31, 2007 and December 31, 2006, respectively.

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Interest Rates

PSEG, Power and PSE&G

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. PSEG s policy is to manage interest rate risk through the use of fixed and floating rate debt and interest rate derivatives.

Fair Value Hedges

PSEG and Power

In March 2004, Power issued $250 million of 3.75% Senior Notes due April 2009. PSEG used an interest rate swap to convert Power s fixed-rate debt into variable-rate debt. The interest rate swap is designated and effective as a fair value hedge. The fair value changes of the interest rate swap are fully offset by the fair value changes in the underlying debt. As of December 31, 2007 and December 31, 2006, the fair value of the hedge was $(2) million and $(9) million, respectively.

Cash Flow Hedges

PSEG and PSE&G

PSEG and PSE&G use interest rate swaps and other interest rate derivatives to manage their exposures to the variability of cash flows, primarily related to variable-rate debt instruments. The interest rate derivatives used are designated and effective as cash flow hedges. Except for PSE&G s cash flow hedges, the fair value changes of these derivatives are initially recorded in Accumulated Other Comprehensive Loss. As of December 31, 2007, the fair value of these cash flow hedges was $(4) million and $(7) million at PSE&G and Energy Holdings, respectively. As of December 31, 2006, the fair value of these cash flow hedges was $(4) million, primarily at PSE&G. The $(4) million at PSE&G as of December 31, 2007 and December 31, 2006, is not included in Accumulated Other Comprehensive Loss, as it is deferred as a Regulatory Asset and is expected to be recovered from PSE&G s customers. During the next 12 months, $2 million of unrealized losses (net of taxes) on interest rate derivatives in Accumulated Other Comprehensive Loss is expected to be reclassified at PSEG. As of December 31, 2007, there was no hedge ineffectiveness associated with these hedges.

Note 12. Commitments and Contingent Liabilities

Nuclear Insurance Coverages and Assessments

Power

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the primary property and decontamination liability insurance at Salem Nuclear Generating Station (Salem), Hope Creek Nuclear Generating Station (Hope Creek) and Peach Bottom Atomic Power Station (Peach Bottom). NEIL also provides excess property insurance through its decontamination liability, decommissioning liability and excess property policy and replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power s maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

The American Nuclear Insurers (ANI) and NEIL policies both include coverage for claims arising out of acts of terrorism. NEIL makes a distinction between certified and non-certified acts of terrorism, as defined under the Terrorism Risk Insurance Act (TRIA), and thus its policies respond accordingly. For non-certified acts of terrorism, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus any amounts available through reinsurance or indemnity for non-certified acts of terrorism. For any act of terrorism,

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power s nuclear liability policies will respond similarly to other covered events. For certified acts, Power s nuclear property NEIL policies will respond similarly to other covered events.

The Price-Anderson Act sets the limit of liability for claims that could arise from an incident involving any licensed nuclear facility in the U.S. The limit of liability is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The current limit of liability is $10.8 billion. All utilities owning a nuclear reactor, including Power, have provided for this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by the Price-Anderson Act. Under the Price-Anderson Act, each party with an ownership interest in a nuclear reactor can be assessed its share of $101 million per reactor per incident, payable at $15 million per reactor per incident per year. If the damages exceed the limit of liability, the President is to submit to Congress a plan for providing additional compensation to the injured parties. Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power s maximum aggregate assessment per incident is $317 million (based on Power s ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $48 million. This does not include the $11 million that could be assessed under the nuclear worker policies. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

Power s insurance coverages and maximum retrospective assessments for its nuclear operations are as follows:

Total Site Coverage

Retrospective Assessments

(Millions)

Type and Source of Coverages

Public and Nuclear Worker Liability (Primary Layer):

ANI

$

300

(A)

$

10

Nuclear Liability (Excess Layer):

Price-Anderson Act

10,461

(B)

317

Nuclear Liability Total.

$

10,761

(C)

$

327

Property Damage (Primary Layer):

NEIL

Primary (Salem/Hope Creek/Peach Bottom).

$

$

500

$

17

Property Damage (Excess Layers):

NEIL II (Salem/Hope Creek/Peach Bottom)

750

9

NEIL Blanket Excess (Salem/Hope Creek/Peach Bottom)

850

(D)

6

Property Damage Total (Per Site)

$

2,100

$

32

Accidental Outage:

NEIL I (Peach Bottom)

$

245

(E)

$

6

NEIL I (Salem)

281

(E)

7

NEIL I (Hope Creek)

490

(E)

6

Replacement Power Total

$

1,016

$

19

(A)

The primary limit for Public Liability is a per site aggregate limit with no potential for assessment. The Nuclear Worker Liability represents the potential liability from workers claiming exposure to the hazard of nuclear radiation. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion and has an assessment potential under former canceled policies.

(B)

Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the U.S. that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of August 20, 2003. The next adjustment is due on or before August 20, 2008. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(C)

Limit of liability under the Price-Anderson Act for each nuclear incident.

(D)

For property limits in excess of $1.25 billion, Power participates in a Blanket Limit policy where the $850 million limit is shared by Power with Amergen Energy Company, LLC (Amergen) and Exelon Generation LLC (Exelon Generation) among the Braidwood, Byron, Clinton, Dresden, La Salle, Limerick, Oyster Creek, Quad Cities, TMI-1 facilities owned by Amergen and Exelon and the Peach Bottom, Salem and Hope Creek facilities. This limit is not subject to reinstatement in the event of a loss. Participation in this program materially reduces Power s premium and the associated potential assessment.

(E)

Peach Bottom has an aggregate indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Salem has an aggregate indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 75 weeks. Hope Creek has an aggregate indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks.

Guaranteed Obligations

Power

Power contracts for electricity, natural gas, oil, coal, pipeline capacity, transportation and emission allowances and engages in risk management activities through ER&T. These activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are executed with numerous counterparties and brokers. Counterparties and brokers may require guarantees, cash or cash-related instruments to be deposited on these transactions as described below.

Power has unconditionally guaranteed payments by its subsidiaries, ER&T and PSEG Power New York Inc. (Power New York) in commodity-related transactions to support current exposure, interest and other costs on sums due and payable in the ordinary course of business. These payment guarantees are provided to counterparties in order to obtain credit. Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction. The face value of the guarantees outstanding as of December 31, 2007 and December 31, 2006 was $1.5 billion and $1.6 billion, respectively.

In order for Power to incur a liability for the face value of the outstanding guarantees, ER&T and Power New York would have to fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee and all of ER&T s and Power New York s contracts would have to be out-of-the-money (if the contracts are terminated, Power would owe money to the counterparties). The probability of all contracts at ER&T and Power New York being simultaneously out-of-the-money is highly unlikely due to offsetting positions within the portfolio. For this reason, the current exposure at any point in time is a more meaningful representation of the potential liability to Power under these guarantees if ER&T and/or Power New York were to default. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any margins posted. The current exposure from such liabilities was $521 million and $518 million as of December 31, 2007 and December 31, 2006, respectively.

Power is subject to counterparty collateral calls related to commodity contracts and is subject to certain creditworthiness standards as guarantor under performance guarantees for ER&T s agreements. Changes in commodity prices, including fuel, emissions allowances and electricity, can have a material impact on margin requirements under such contracts. As of December 31, 2007 and December 31, 2006, Power had the following margin posted and received to satisfy collateral obligations, which were primarily in the form of letters of credit:

As of December 31, 2007

As of
December 31,
2006

(Millions)

Margin Posted

$

188

$

40

Margin Received

$

44

$

86

135

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Power also routinely enters into exchange-traded futures and options transactions for electricity and natural gas as part of its operations. Generally, such futures contracts require a deposit of cash margin, the amount of which is subject to change based on market movement and in accordance with exchange rules. As of December 31, 2007 and December 31, 2006, Power had deposited margin of $168 million and $89 million, respectively.

In the event of a deterioration of Power s credit rating to below investment grade, which would represent a two level downgrade from its current ratings, many of these agreements allow the counterparty to demand that ER&T provide further performance assurance. Exchange-traded transactions that are margined and monitored separately from physical trading activity may not be subject to change in the event of a downgrade to Power s rating. As of December 31, 2007, if Power were to lose its investment grade rating and, assuming all counterparties to which ER&T is out-of-the-money were contractually entitled to demand, and demanded, performance assurance, ER&T could be required to post additional collateral in an amount equal to $777 million. Power believes that it has sufficient liquidity to post such collateral, if necessary.

In addition to amounts discussed above, Power had posted $37 million in letters of credit as of December 31, 2007 and 2006 to support various other contractual and environmental obligations.

Environmental Matters

PSEG, Power and PSE&G

Passaic River

The U.S. Environmental Protection Agency (EPA) has determined that a six-mile stretch of the Passaic River in the area of Newark, New Jersey is a facility within the meaning of that term under the Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA).

PSE&G and certain of its predecessors conducted industrial operations at properties adjacent to the Passaic River facility. The operations included one operating electric generating station (Essex Site), one former generating station and four former MGPs. PSE&G s costs to clean up former MGPs are recoverable from utility customers through the SBC. PSE&G has sold the site of the former generating station. The Essex Site was transferred to Power in August 2000. Power assumed any environmental liabilities of PSE&G associated with the electric generating stations that PSE&G transferred to it, including the Essex Site.

In 2003, the EPA notified 41 potentially responsible parties (PRPs), including Power and PSE&G, that it was expanding its assessment of the Passaic River Study Area to the entire 17-mile tidal reach of the lower Passaic River. The EPA further indicated, with respect to PSE&G, that it believed that hazardous substances had been released from the Essex Site and a former MGP located in Harrison, New Jersey (Harrison Site), which also includes facilities for PSE&G s ongoing gas operations. The EPA estimated that its study would require five to eight years to complete and would cost $20 million, of which it would seek to recover $10 million from the PRPs, including Power and PSE&G. In 2006, the EPA notified the PRPs that the cost of its study will greatly exceed the $20 million initially estimated and after discussion, approximately 70 PRPs, including Power and PSE&G, have agreed to assume responsibility for the study pursuant to an Administrative Order on Consent and to divide the associated costs among themselves according to a mutually agreed-upon formula. The percentage allocable to Power and PSE&G varies depending on the number of PRPs who have agreed to divide the costs but it currently approximates 5%, approximately 80% of which is attributable to PSE&G s former MGPs and approximately 20% to Power s generating station. Power has provided notice to insurers concerning this potential claim.

In June 2007, the EPA announced a draft Focused Feasibility Study (FFS) that proposes six options with estimated costs ranging from $900 million to $2.3 billion to address contamination cleanup in the lower eight miles of the Passaic River in addition to a No Action alternative. The work contemplated by the FFS is not subject to the Administrative Order on Consent or the cost sharing agreement. The EPA is reviewing comments received on the draft FFS.

CERCLA and the New Jersey Spill Compensation and Control Act (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 New Jersey Department of

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Environmental Protection (NJDEP) requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP has regulations in effect 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. In 2003, PSEG, PSE&G and 56 other PRPs received a Directive and Notice to Insurers from the NJDEP that directed the PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the Spill Act. The NJDEP alleged in the Directive that it had determined that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP announced that it had estimated the cost of interim natural resource injury restoration activities along the lower Passaic River to approximate $950 million. On August 2, 2007, the National Oceanic and Atmospheric Administration of the United States Department of Commerce sent a letter to PSE&G and other companies identified as PRPs notifying them that it intended to perform an assessment of injuries to natural resources and inviting the PRPs to participate. The PRPs have not agreed to participate in either of these natural resource damage initiatives.

Newark Bay Study Area

The EPA sent PSE&G and eleven other entities notices that the EPA considered each of the entities to be a PRP with respect to contamination in the Newark Bay Study Area, which it defined as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. The notice letter requested that the PRPs participate and fund the EPA-approved study in the Newark Bay Study Area and encouraged the PRPs to contact Occidental Chemical Corporation (OCC) to discuss participating in the Remedial Investigation/Feasibility Study (RI/FS) that OCC is conducting in the Newark Bay Study Area. EPA considers the Newark Bay Study Area, along with the Passaic River Study Area, to be part of the Diamond Alkali Superfund Site. The notice states the EPA s belief that hazardous substances were released from sites owned by PSE&G and located on the Hackensack River. The sites included two operating electric generating stations (Hudson and Kearny Sites), and one former MGP. PSE&G s costs to clean up former MGPs are recoverable from utility customers through the SBC. The Hudson and Kearny Sites were transferred to Power in August 2000. Power assumed any environmental liabilities of PSE&G associated with the electric generating stations that PSE&G transferred to it, including the Hudson and Kearny Sites. Power has provided notice to insurers concerning this potential claim. Power and PSE&G are unable to estimate the cost of the investigation at this time.

Other

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 other 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, discussed below. 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, Power and PSE&G 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.

PSE&G

MGP Remediation Program

PSE&G is currently working with the NJDEP under a program to assess, investigate and remediate environmental conditions at PSE&G s former MGP sites (Remediation Program). To date, 38 sites have been identified as sites requiring some level of remedial action. In addition, the NJDEP has announced initiatives to accelerate the investigation and subsequent remediation of the riverbeds underlying surface water bodies that have been impacted by hazardous substances from adjoining sites. Specifically, in 2005, the NJDEP initiated a program on the Delaware River aimed at identifying the 10 most significant sites for

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cleanup. One of the sites identified is PSE&G s former Camden Coke facility located in Camden. The Remediation Program is periodically reviewed, and the estimated costs are revised by PSE&G based on regulatory requirements, experience with the program and available remediation technologies.

During the fourth quarter of 2007, PSE&G refined the detailed site estimates. Based on that review, the remaining cost of remediating all sites to completion, as well as the anticipated costs to address MGP-related material discovered in three rivers adjacent to two former MGP sites, could range between $639 million and $812 million through 2021. Since no amount within the range was considered to be most likely, the low end of the range, $639 million, was accrued as of December 31, 2007. Of this amount, $45 million was recorded in Other Current Liabilities and $594 million was reflected in Other Noncurrent Liabilities. The costs associated with the MGP Remediation Program have historically been recovered through the SBC charges to PSE&G ratepayers. As such, a $639 million Regulatory Asset was recorded. PSE&G s costs for the Remediation Program were $44 million for 2007.

Power

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act, require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a major modification, as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties of up to $27,500 for each day of continued violation.

On November 30, 2006, Power reached an agreement with the EPA and the New Jersey Department of Environmental Protection (NJDEP) to achieve emissions reductions targets consistent with an earlier consent decree that resolved allegations of non-compliance with NSR/PSD programs at the company s Mercer, Hudson and Bergen generating stations. Under this agreement and the consent decree Power is required to undertake a number of technology projects, plant modifications and operating procedure changes at Hudson and Mercer designed to meet targeted reductions in emissions of Sulfur Dioxide (SO2), Nitrogen Oxide (NOx), particulate matter and mercury.

Pursuant to this program, Power has installed selective catalytic reductions at Mercer at a cost of $129 million. The cost of implementing the balance of the agreement is estimated at $475 million to $525 million for Mercer to be completed by May 2010 and $700 million to $750 million for Hudson to be completed by the end of 2010. Fossil also purchased and retired emissions allowances by July 31, 2007, paid a $6 million civil penalty and have agreed to contribute $3 million for programs to reduce particulate emissions from diesel engines in New Jersey. In March 2007, Fossil entered into an engineering, procurement and construction contract with a third party contractor to complete all back-end technology requirements for the Mercer station, as referenced above. Fossil signed a contract for construction management related to the Hudson back-end technology construction in July 2007.

As a result of the agreement, Power s environmental reserves include $3 million to account for the particulate matter reduction program. PSEG and Power recorded the charge in Other Deductions on their respective Condensed Consolidated Statements of Operations in the fourth quarter of 2006.

Mercury Regulation

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.

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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 PSD and NSR air pollution control programs discussed above.

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 Clean Air Interstate Rule. 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. Total estimated costs for each project are between $150 million and $200 million. The costs for Mercer and Hudson are included in the cost estimates referred to in the PSD/NSR discussion above.

Power

New Jersey Industrial Site Recovery Act (ISRA)

Potential environmental liabilities related to subsurface contamination at certain generating stations have been identified. In the second quarter of 1999, in anticipation of the transfer of PSE&G s generation-related assets to Power, a study was conducted pursuant to ISRA, which applied to the sale of certain assets. Power had a $50 million liability as of December 31, 2007 and December 31, 2006 related to these obligations, which is included in Environmental Costs on Power s and PSEG s Condensed Consolidated Balance Sheets.

Permit Renewals

In June 2001, the NJDEP issued a renewed (NJPDES) permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. A renewal application prepared in accordance with Federal Water Pollution Control Act (FWPCA) Section 316(b) and the Phase II 316(b) rule was filed in January 2006 with the NJDEP, which allows the station to continue operating under its existing NJPDES permit until a new permit is issued. Power s application to renew Salem s NJPDES permit demonstrates that the station satisfies FWPCA Section 316(b) and meets the Phase II 316(b) rule s performance standards for reduction of impingement and entrainment through the station s existing cooling water intake technology and operations plus implemented restoration measures. The application further demonstrates that even without the benefits of restoration, the station meets the Phase II 316(b) rule s site-specific determination standards, both on a comparison of the costs and benefits of new intake technology as

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well as a comparison of the costs to implement the technology at the facility to the cost estimates prepared by the EPA.

On January 25, 2007, the U.S. Court of Appeals for the Second Circuit issued its decision in litigation of the Phase II 316(b) 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 FWPCA does not support the use of restoration and the site-specific cost-benefit test. The court instructed the EPA to reconsider the definition of best technology available 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.

On May 25, 2007, Power and other industry petitioners filed with the Second Circuit Court a request for a rehearing. In July 2007, the Second Circuit Court denied the request. The parties, including Power, have requested that the US Supreme Court review the matter. The Northeast states and the Solicitor General have received an extension to file their oppositions to those petitions, up through and including February 29, 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 EPA for further consideration.

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. Depending on the outcome of any appeals, or actions by the EPA to promulgate a revised rule, this decision could have a material impact on Power s ability to renew its New Jersey and Connecticut permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to their existing intake structures and cooling systems. If the NJDEP and the Connecticut Department of Environmental Protection were to require installation of closed-cycle cooling or its equivalent at these once-through cooled facilities, the related costs and impacts would be material to Power s financial position, results of operations and net cash flows. For example, Power s 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. Potential costs associated with any closed-cycle cooling requirements are not included in Power s currently forecasted capital expenditures.

New Generation and Development

Power

Power plans to modestly increase its generating capacity at Hope Creek and Salem Unit 2 in 2008. Phase I of the Hope Creek turbine replacement increased the capacity by 10 MW in 2005, and Phase II, which is expected to add approximately 125 MW of capacity, is expected to be completed in the second quarter of 2008 along with the Extended Power Uprate (EPU). Phase I of the Salem Unit 2 turbine upgrade increased Power s share of the capacity by 14 MW in 2003. Phase II is currently scheduled for the spring of 2008, concurrent with steam generator replacement and is anticipated to increase Power s share of the capacity by an additional 15 MW. As of December 31, 2007, Power s expenditures for these projects were $200 million (including IDC of $23 million) with an aggregate estimated share of total costs for these projects of $216 million (including IDC of $28 million).

Completion of the projects discussed above within the estimated time frames and cost estimates cannot be assured. Construction delays, cost increases and various other factors could result in changes in the operational dates or ultimate costs to complete.

Power entered into a long-term contractual services agreement with a vendor in September 2003 to provide the outage and service needs for certain of Power s generating units at market rates. The contract covers 25 years and could result in annual payments ranging from $10 million to $50 million for services, parts and materials rendered.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

BGS and BGSS

Power and PSE&G

PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for customers who do not purchase electric supply from third-party suppliers. PSE&G enters into the Supplier Master Agreement (SMA) with the winners of these BGS auctions within three business days following the BPU s approval. PSE&G has entered into contracts with Power, as well as with other winning BGS suppliers, to purchase BGS for PSE&G s anticipated load requirements. The winners of the auction are responsible for fulfilling all the requirements of a PJM Load Serving Entity including capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume any customer migration risk and must satisfy New Jersey s renewable portfolio standards.

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.

Power seeks to mitigate volatility in its results by contracting in advance for its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey Electric Distribution Companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above. In addition to the BGS-related contracts, Power enters into firm supply contracts with EDCs, as well as other firm sales and commitments.

PSE&G has a full requirements contract with Power to meet the gas supply requirements of PSE&G s gas customers. The contract extends through March 31, 2012, and year-to-year thereafter. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits recovery of the cost of gas hedging up to 115 billion cubic feet or approximately 80% of PSE&G s residential gas supply annually through the BGSS tariff. For additional information, see Note 21. Related-Party Transactions.

The BPU is currently conducting an audit of the gas procurement practices of all four New Jersey gas utilities, including PSE&G. The outcome of this proceeding cannot be predicted.

Minimum Fuel Purchase Requirements

Power

Power purchases coal and oil for certain of its fossil generation stations through various long-term commitments. The total minimum purchase requirements included in these commitments amount to approximately $1 billion through 2012.

Power has several long-term purchase contracts for the supply of nuclear fuel for the Salem and Hope Creek nuclear generating stations. Power has inventory and commitments to purchase sufficient quantities of uranium (concentrates and uranium hexafluoride) to meet 100% of its total estimated requirements through 2011. Power has commitments for concentrates covering approximately 60% of its estimated requirements for 2012, 30% from 2013 through 2014 and 20% through 2016. Additionally, Power has commitments for uranium hexafluoride to meet 92% of its estimated requirements for 2012, 50% for 2013 and 2014, and 20% for 2015 and 2016. These commitments, based on current market prices, which have increased substantially over the past two to three years, total $574 million ($402 million Power s estimated share). Power s policy is to maintain certain levels of concentrates and uranium hexafluoride in inventory and to make periodic

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

purchases to support such levels. As such, the commitments referred to above include estimated quantities to be purchased that are in excess of contractual minimum quantities.

Power also has commitments that provide 100% of its uranium enrichment requirements through 2011, 35% for 2012 and 26% for 2013, totaling $306 million ($203 million Power s estimated share).

Power has commitments that provide 100% of the fabrication of fuel assemblies for reloads required through 2011 for Salem and through 2012 for Hope Creek that total approximately $124 million ($90 million Power s estimated share).

Exelon Generation has informed Power that the Peach Bottom plant has inventory and commitments to purchase sufficient quantities of uranium (concentrates and uranium hexafluoride) to meet 100% of its total estimated requirements through 2010. Additionally, Exelon Generation has commitments covering approximately 100% of its estimated requirements for 2011 and 47% for 2012.

Exelon Generation also has commitments that provide 100% of its uranium enrichment requirements for the Peach Bottom plant in 2008, 2010 and 2012. Additionally, Peach Bottom has a 94% commitment in 2009 and an 82% commitment in 2011.

Exelon Generation has commitments for the fabrication of fuel assemblies for reloads required through 2012 for Peach Bottom. In total, the Exelon Generation commitment for nuclear fuel, conversion, enrichment and fabrication totals $406 million ($203 million Power s estimated share).

Natural Gas

In addition to its fuel requirements, Power has entered into various multi-year contracts for firm transportation and storage capacity for natural gas, primarily to meet its gas supply obligations to PSE&G. As of December 31, 2007, the total minimum requirements under these contracts were approximately $1 billion through 2016.

These purchase obligations are consistent with Power s strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

PSEG Texas

The Texas generation facilities have entered into gas supply agreements for their anticipated fuel requirements to satisfy obligations under their forward energy sales contracts. As of December 31, 2007, the plants had fuel purchase commitments totaling $106 million to support all of their contracted energy sales.

Regulatory Proceedings

PSEG and 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 was granted. PSE&G s motion to dismiss the BPU petition is pending.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Investment Tax Credits

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, PSE&G 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. 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 PSE&G 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.

BPU Deferral Audit

The BPU Energy and Audit Division conducts audits of deferred balances under various adjustment clauses. 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 addresses the SBC, MTC and NUG deferred balances. The BPU released the report on May 13, 2005.

While the consultant to the BPU found that the Phase II deferral balances complied in all material respects with the BPU Orders regarding such deferrals, the consultant noted that the BPU Staff had 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 Phase I and Phase II four-year transition period. The amount in dispute is $114 million, which if required to be refunded to customers with interest through December 2007, would be $127 million.

At PSE&G s request, the matter was transmitted to the Office of Administrative Law for the development of an evidentiary record and an initial decision. The BPU granted the request on February 7, 2007. On May 25, 2007, PSE&G filed a motion for Summary Judgement requesting dismissal of the matter. On September 28, 2007, the Administrative Law Judge issued an initial decision denying PSE&G s motion to dismiss the matter and ordering the filing of testimony and evidentiary hearings. Hearing dates have been established for July 16, 2008 to July 18, 2008. The BPU Staff and New Jersey Public Advocate s Division of Rate Counsel have both asserted in briefs that the disputed amount be refunded to customers.

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 impact of the outcome of this proceeding.

New Jersey Clean Energy Program

The BPU has approved a funding requirement for each New Jersey utility applicable to its Renewable Energy and Energy Efficiency programs for the years 2005 to 2008. The sum of PSE&G s electric and gas funding requirement was $120 million and $96 million for the years ended December 31, 2007 and 2006, respectively. The remaining liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are expected to be recovered from PSE&G ratepayers through the SBC. The liability for the funding requirement as of December 31, 2007 and December 31, 2006 was $149 million and $253 million, respectively.

Energy Holdings

Leveraged Lease Investments

On November 16, 2006, the Internal Revenue Service (IRS) issued its Revenue Agents report for tax years 1997 through 2000, which disallowed all deductions associated with certain 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.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

If all deductions associated with these lease transactions, entered into by Energy Holdings between 1997 and 2002, are successfully challenged by the IRS, it could have a material adverse impact on PSEG s financial position, results of operations and net cash flows and could impact future returns on these transactions. PSEG believes that its tax position related to these transactions is proper based on applicable statutes, regulations and case law and will aggressively contest the IRS disallowance. PSEG believes that it is more likely than not that it will prevail with respect to the IRS challenge, although no assurances can be given.

If the IRS disallowance of tax benefits associated with all of these lease transactions was sustained, $878 million of PSEG s 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. PSEG s management has assessed the probability of various outcomes to this matter and recorded the tax effect to be realized in accordance with FIN 48. 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.

For additional information and guidance for leveraged leases. See Note 2. Recent Accounting Standards for additional information.

Minimum Lease Payments

PSEG, Power and PSE&G

PSEG and Power have entered into capital leases for administrative office space. The total future minimum payments and present value of these capital leases as of December 31, 2007 are:

Power

Other

(Millions)

2008

$

2

$

20

2009

2

20

2010

2

16

2011

2

10

2012

2

10

Thereafter.

5

26

Total Minimum Lease Payments

Less: Imputed Interest

(6

)

(65

)

Present Value of Net Minimum Lease Payments

$

9

$

37

PSEG and PSE&G lease administrative office space under various operating leases. Total future minimum lease payments as of December 31, 2007 are $14 million, including $11 million at PSE&G.

Note 13. Nuclear Decommissioning

Power

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning.

Power maintains the external master nuclear decommissioning trust previously established by PSE&G. This trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. In the most recent study of the total cost of decommissioning, Power s share related to its five nuclear units was estimated at approximately $2.1 billion, including contingencies.

Power s policy is that, except for investments tied to market indexes or other non-nuclear sector common trust funds or mutual funds (e.g., an S&P 500 mutual fund), assets of the trust shall not be invested

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

in the securities or other obligations of PSEG or its affiliates, or its successors or assigns; and assets shall not be invested in securities of any entity owning one or more nuclear power plants.

Power classifies investments in the NDT Funds as available-for-sale under SFAS 115. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Funds.

As of December 31, 2007

Cost

Gross Unrealized Gains

Gross Unrealized Losses

Estimated
Fair
Value

(Millions)

Equity Securities

$

573

$

191

$

(5

)

$

759

Debt Securities

Government Obligations

213

8

221

Other Debt Securities

253

4

257

Total Debt Securities.

466

12

478

Other Securities

38

3

(2

)

39

Total Available-for-Sale Securities

$

1,077

$

206

$

(7

)

$

1,276

As of December 31, 2006

Cost

Gross Unrealized Gains

Gross Unrealized Losses

Estimated Fair Value

(Millions)

Equity Securities

$

571

$

217

$

(3

)

$

785

Debt Securities

Government Obligations

215

2

217

Other Debt Securities

211

4

215

Total Debt Securities

426

6

432

Other Securities

38

1

39

Total Available-for-Sale Securities

$

1,035

$

224

$

(3

)

$

1,256

Years Ended December 31,

2007

2006

2005

(Millions)

Proceeds from Sales.

$

1,672

$

1,405

$

3,223

Gross Realized Gains

$

164

$

98

$

132

Gross Realized Losses

$

88

$

54

$

36

In 2007, other-than-temporary impairments of $46 million and $26 million were recognized on $339 million of equity and $813 million of debt securities, respectively, that were included in the Estimated Fair Value of NDT Funds as of December 31, 2007.

Net realized gains of $76 million were recognized in Other Income and Other Deductions on Power s Consolidated Statement of Operations for the year ended December 31, 2007. Net unrealized gains of $97 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on Power s Consolidated Balance Sheet as of December 31, 2007. The $7 million of gross 2007 unrealized losses has been in an unrealized loss position for less than twelve months. The available-for-sale debt securities held as of December 31, 2007, had the following maturities: $7 million less than one year, $75 million one to five years, $125 million five to 10 years, $55 million 10 to 15 years, $24 million 15 to 20 years, and $192 million over 20 years. The cost of these securities was determined on the basis of specific identification.

The fair value of securities in an unrealized loss position as of December 31, 2007 was approximately $151 million. If the fair market value of the securities falls below cost, the investments are considered to be other-than-temporarily impaired. The difference between the fair market value and cost is recorded as a charge to earnings since Power does not definitely have the ability and intent to hold the securities for a reasonable time to permit recovery. Any subsequent recoveries in the value of these securities are recognized in Other Comprehensive Income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost detail of the securities.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

In addition to the net realized gains, Power also records interest and dividend income, other-than-temporary impairments and other costs related to the NDT Fund in Other Income and Deductions. The total amounts recorded in Other Income and Deduction related to the NDT Fund, including the net realized gains, were $48 million, $64 million and $125 million for the years ended December 31, 2007, 2006 and 2005, respectively. The interest accretion expense on Power s ARO liability, which primarily relates to the decommissioning of the nuclear power plants for which the NDT Fund is maintained, is recorded in Operation and Maintenance Expense and was $23 million, $33 million and $28 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Note 14. Other Income and Deductions

Other Income

Power

PSE&G

Other(A)

Consolidated Total

(Millions)

For the Year Ended December 31, 2007:

Interest and Dividend Income

$

21

$

10

$

5

$

36

Gain on Disposition of Property

3

3

NDT Fund Realized Gains

164

164

NDT Interest, Dividend and Other Income

50

50

Change in Derivative Fair Value.

8

8

Arbitration Award (Konya-Ilgin)

9

9

Minority Interest

2

2

Other

4

3

3

10

Total Other Income

$

239

$

16

$

27

$

282

<u>For the Year Ended December 31, 2006</u>:

Interest and Dividend Income

$

13

$

11

$

12

$

36

Gain on Disposition of Property

1

4

5

NDT Fund Realized Gains

98

98

NDT Interest, Dividend and Other Income

40

40

Foreign Currency Gains

2

2

Gain on Early Extinguishment of Debt

1

1

Contributions in Aid of Construction

9

9

Albany Contingency

4

4

Other

1

1

4

6

Total Other Income

$

157

$

25

$

19

$

201

For the Year Ended December 31, 2005:

Interest and Dividend Income

$

11

$

11

$

12

$

34

Gain on Disposition of Property

5

3

1

9

Gain on Investments

8

8

NDT Fund Realized Gains

132

132

NDT Interest, Dividend and Other Income

35

35

Foreign Currency Gains

4

4

Other

4

1

2

7

Total Other Income

$

187

$

15

$

27

$

229

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power

PSE&G

Other(A)

Consolidated Total

(Millions)

For the Year Ended December 31, 2007:

Donations

$

$

3

$

22

$

25

NDT Fund Realized Losses and Expenses

166

166

Change in Derivative Fair Value

15

15

Loss on Retirement of Property, Plant and Equipment

2

2

Loss on Early Retirement of Debt

47

47

Other

2

1

1

4

Total Other Deductions

$

170

$

4

$

85

$

259

For the Year Ended December 31, 2006:

Donations

$

$

2

$

$

2

NDT Fund Realized Losses and Expenses

74

74

Minority Interest

1

1

Change in Derivative Fair Value

2

2

Loss on Retirement of Property, Plant and Equipment

1

1

Environmental Reserves

15

15

Loss on Early Retirement of Debt

12

12

Other

1

1

4

6

Total Other Deductions

$

91

$

3

$

19

$

113

For the Year Ended December 31, 2005:

Donations

$

$

2

$

13

$

15

NDT Fund Realized Losses and Expenses

42

42

Loss on Early Retirement of Debt

10

10

Foreign Currency Losses

10

10

Minority Interest

1

1

Change in Derivative Fair Value

3

3

Loss on Retirement of Property, Plant and Equipment.

1

1

2

4

Total Other Deductions

$

43

$

3

$

39

$

85

(A)

Other primarily consists of activity at PSEG (parent company), Energy Holdings, Services and intercompany eliminations.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 15. Income Taxes

A reconciliation of reported income tax expense for PSEG with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

2007

2006

2005

(Millions)

Net Income

$

1,335

$

739

$

661

Income (Loss) from Discontinued Operations, including Gain (Loss) On Disposal, net of tax (expense) benefit

16

60

(159

)

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

(17

)

Minority Interest in Earnings of Subsidiaries

2

(1

)

(1

)

Income from Continuing Operations, excluding Minority Interests

1,317

680

838

Preferred Dividends (net)

(4

)

(4

)

(4

)

Income from Continuing Operations, excluding Minority Interests and Preferred Dividends, net

$

1,321

$

684

$

842

Income taxes:

Operating income:

Federal Current

$

705

$

331

$

230

Deferred (A)

143

33

230

Investment Tax Credit (ITC)

(4

)

(4

)

(4

)

Total Federal

844

360

456

State Current

155

81

106

Deferred (A)

58

10

(15

)

Total State

213

91

91

Total Foreign

3

9

2

Total Income Taxes

1,060

460

549

Pre-tax Income

$

2,381

$

1,144

$

1,391

Tax Computed at the Statutory Rate @35%

$

833

$

400

$

486

Increase (Decrease) Attributable to Flow-Through of
Certain Tax Adjustments:

Foreign Operations

95

8

11

Other

(12

)

(3

)

(12

)

State Income Tax (net of Federal Income Tax)

144

55

64

Subtotal

227

60

63

Total Income Tax Provision

$

1,060

$

460

$

549

Effective Income Tax Rate

44.5

%

40.2

%

39.5

%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSEG:

2007

2006

(Millions)

Deferred Income Taxes

Assets:

Current (net)

$

$

36

Non-current:

Unrecovered ITC.

14

15

OCI

313

231

Cumulative Effect of a Change in Accounting Principle

11

11

New Jersey Corporate Business Tax

166

201

OPEB.

188

161

Cost of Removal

51

51

Investment Related Adjustment

9

Development Fees

10

10

Contractual Liabilities and Environmental Costs

35

35

MTC

18

11

Related to Uncertain Tax Positions

286

Other

13

22

Total Non-current

1,105

757

Total Assets

$

1,105

$

793

Liabilities:

Current (net)

$

106

$

Non-current:

Plant-Related Items

1,627

1,361

OCI

2

Nuclear Decommissioning

132

131

Securitization.

1,001

1,110

Leasing Activities

1,984

1,842

Partnership Activity

86

51

Repair Allowance Deferred Carrying Charge

19

22

Conservation Costs

10

12

Energy Clause Recoveries

34

27

Pension Costs

119

100

SFAS 143

325

325

Taxes Recoverable Through Future Rate (net).

167

167

Related to Foreign Operations

3

(2

)

Other

(1

)

(4

)

Total Non-current Liabilities

5,508

5,142

Total Liabilities

$

5,614

$

5,142

Summary of Accumulated Deferred Income Taxes:

Net Current Assets

$

$

36

Net Current Liabilities

106

Net Non-current Liability

4,403

4,385

Total

4,509

4,349

ITC

51

55

Current Portion of SFAS 109 Transferred

44

36

Current Liabilities-APB 23/Foreign Currency Translation Transferred

(150

)

Total Deferred Income Taxes and ITC

$

4,454

$

4,440

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for Power with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

2007

2006

2005

(Millions)

Net Income

$

941

$

276

$

192

Loss from Discontinued Operations, including Loss On Disposal, net of tax benefit

(8

)

(239

)

(226

)

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

(16

)

Income from Continuing Operations

$

949

$

515

$

434

Income taxes:

Operating income:

Federal Current

$

420

$

263

$

105

Deferred (A)

78

20

147

Total Federal

498

283

252

State Current

121

78

44

Deferred (A)

22

2

22

Total State

143

80

66

Total Income Taxes

641

363

318

Pre-tax income

$

1,590

$

878

$

752

Tax Computed at the Statutory Rate @35%

$

557

$

307

$

263

Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:

State Income Tax (net of Federal Income Tax)

93

52

43

Other

(9

)

4

12

Subtotal

84

56

55

Total Income Tax Provision

$

641

$

363

$

318

Effective Income Tax Rate

40.3

%

41.3

%

42.3

%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for Power:

2007

2006

(Millions)

Deferred Income Taxes

Assets:

Current (net)

$

$

Non-current:

OCI

290

193

Cumulative Effect of a Change in Accounting Principle

11

11

New Jersey Corporate Business Tax

76

77

Cost of Removal

51

51

Contractual Liabilities and Environmental Costs

35

35

Related to Uncertain Tax positions

2

Total Non-current

465

367

Total Assets

$

465

$

367

Liabilities:

Current

$

$

Non-current:

Plant-Related Items

185

(35

)

Nuclear Decommissioning

132

131

Pension Costs

32

14

SFAS 143

325

325

Other

(38

)

(26

)

Total Non-current Liabilities

636

409

Total Liabilities

$

636

$

409

Summary of Accumulated Deferred Income Taxes:

Net Current Assets

$

$

Net Non-current Liability

171

42

Total

171

42

ITC

5

6

Total Deferred Income Taxes and ITC	$	176	$	48

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A reconciliation of reported income tax expense for PSE&G with the amount computed by multiplying pre-tax income by the statutory federal income tax rate of 35% is as follows:

2007

2006

2005

(Millions)

Net Income

$

376

$

261

$

344

Preferred Dividends (net)

(4

)

(4

)

(4

)

Income from Continuing Operations, Excluding Preferred Dividends, net

380

265

348

Income taxes:

Operating income:

Federal Current

214

299

239

Deferred (A)

(22

)

(161

)

(58

)

ITC

(3

)

(3

)

(3

)

Total Federal

189

135

178

State Current

67

49

49

Deferred (A)

1

(1

)

8

Total State

68

48

57

Total Income Taxes

257

183

235

Pre-tax Income

$

637

$

448

$

583

Tax Computed at the Statutory Rate @35%

$

223

$

157

$

204

Increase (Decrease) Attributable to Flow-Through of Certain Tax Adjustments:

State Income Tax (net of Federal Income Tax)

44

31

37

Other

(10

)

(5

)

(6

)

Subtotal

34

26

31

Total Income Tax Provision

$

257

$

183

$

235

Effective Income Tax Rate

40.3

%

40.8

%

40.3

%

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following is an analysis of deferred income taxes for PSE&G:

2007

2006

(Millions)

Deferred Income Taxes

Assets:

Current (net)

$

44

$

36

Non-current:

Unrecovered ITC

14

15

New Jersey Corporate Business Tax

131

145

OPEB.

185

160

MTC

18

11

Related to Uncertain Tax Positions

14

Other

1

5

Total Non-current

363

336

Total Assets

$

407

$

372

Liabilities:

Current:

$

$

Non-current:

Plant-Related Items

1,445

1,398

OCI

2

Securitization.

1,001

1,110

Repair Allowance Deferred Carrying Charge

19

22

Conservation Costs

10

12

Energy Clause Recoveries

34

27

Pension Costs

73

73

Taxes Recoverable Through Future Rates (net).

167

167

Other

11

Total Non-current Liabilities

2,762

2,809

Total Liabilities

$

2,762

$

2,809

Summary of Accumulated Deferred Income Taxes:

Net Current Assets

$

44

$

36

Net Non-current Liability

2,399

2,473

Total

2,355

2,437

ITC

41

44

Current Portion of SFAS 109 Transferred

44

36

Total Deferred Income Taxes and ITC

$

2,440

$

2,517

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSEG, Power and PSE&G

Each of PSEG, Power and PSE&G provide deferred taxes at the enacted statutory tax rate for all temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities irrespective of the treatment for rate-making purposes. Management believes that it is probable that the accumulated tax benefits that previously have been treated as a flow-through item to PSE&G customers will be recovered from PSE&G s customers in the future. Accordingly, an offsetting regulatory asset was established. As of December 31, 2007, PSE&G had a regulatory asset of $420 million representing the tax costs expected to be recovered through rates based upon established regulatory practices, which permit recovery of current taxes payable. This amount was determined using the enacted federal income tax rate of 35% and state income tax rate of 9%.

The 2005 Jobs Act provided a one-year window to repatriate earnings from foreign investments and claim a special 85% dividends received tax deduction on such distributions. PSEG approved a total of three Domestic Reinvestment Plans, which provided for the repatriation of $242 million through December 2005, of which $177 million was eligible for the reduced tax rate pursuant to the 2005 Jobs Act. The tax expense associated with such repatriation totaled $11 million and was recorded in 2005.

PSEG and its subsidiaries adopted FIN 48 effective January 1, 2007, which prescribes a model for how a company should recognize, measure, present and disclose in its financial statements uncertain tax positions that it has taken or expects to take on a tax return. For additional information, see Note 2. Recent Accounting Standards. PSEG recorded the following amounts related to its uncertain tax positions, which is primarily comprised of amounts recorded for Power, PSE&G and Energy Holdings:

PSEG

(Millions)	Power	PSE&G	Energy Holdings
Total Amount of Unrecognized Tax Benefits At the Date of Adoption	$ 485	$ 21	$ 55

$

408

Increases as a result of positions taken in a prior period

81

3

14

64

Decreases as a result of positions taken in a prior period

(35

)

(8

)

(27

)

Increases as a result of positions taken during the current period

41

2

10

29

Decreases as a result of positions taken during the current period

(16

)

(1

)

(12

)

Decreases as a result of Settlements with taxing authorities

Decreases due to lapses of applicable statute of limitations

Total Amount of Unrecognized Tax Benefits at
December 31, 2007

556

18

78

462

Accumulated Deferred Income Taxes associated with Unrecognized Tax Benefits

(286

)

(2

)

(14

)

(272

)

Regulatory Asset-Unrecognized Tax Benefits

(38

)

(38

)

Total Amount of Unrecognized Tax Benefits that if recognized, would impact the effective tax rate (including interest and penalties)

$

232

$

16

$

26

$

190

On December 17, 2007, PSEG made a tax deposit with the IRS in the amount of $100 million to defray interest costs associated with disputed tax assessments associated with certain lease investments (see Note 12. Commitments and Contingent Liabilities). The $100 million deposit is fully refundable and is recorded as a reduction to the Unrecognized Tax Benefit liability on the PSEG s Consolidated Balance Sheet, but is not reflected in the amounts shown above.

PSEG and its subsidiaries include all accrued interest and penalties, required to be recorded under FIN 48, as income tax expense. PSEG s interest and penalties on Unrecognized Tax Benefits as of December 31, 2007 was $142 million, including $4 million at Power, $13 million at PSE&G and $125 million at Energy Holdings.

It is reasonably possible that approximately $31 million of unrecognized tax benefits associated with various items included in federal income tax returns for years 2001-2003 will be settled within 12 months due to agreement with the IRS s position with respect to these items. This amount includes $(8) million for

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power, $7 million for PSE&G and $33 million for Energy Holdings. This amount relates to a number of miscellaneous adjustments proposed by the Internal Revenue Service with which PSEG does not take issue.

It is reasonably possible that approximately $4 million of unrecognized tax benefits associated with various items applicable to Energy Holdings included in federal income tax returns for years 1997- 2000 will be settled within 12 months due to a agreement with the IRS with regard to these items. These issues dealt with the computation of gain on a transfer of certain investments outside the United States.

It is reasonably possible that approximately $(4) million of unrecognized tax benefits associated with a change in accounting method for federal income tax purposes will be settled within 12 months due to agreement with the IRS s position with respect to these items. The change in method related to PSE&G s adoption of the Simplified Service cost method of capitalizing indirect costs.

Description of Income Tax years that remain subject to examination by material jurisdictions, where an examination has not already concluded:

PSEG

Power

PSE&G

United States

Federal

2001-2006

2001-2006

2001-2006

New Jersey

2000-2006

N/A

2000-2006

Pennsylvania.

2003-2006

N/A

2003-2006

Connecticut.

2003-2006

N/A

N/A

Texas

2006

N/A

N/A

California

2002-2006

N/A

N/A

Indiana

2003-2006

N/A

N/A

Ohio

2003-2005

N/A

N/A

Foreign

Chile

2004-2006

N/A

N/A

Peru

2002-2006

N/A

N/A

Note 16. Pension, OPEB and Savings Plans

PSEG

PSEG sponsors several qualified and nonqualified pension plans and other postretirement benefit plans covering PSEG s, and its participating affiliates, current and former employees who meet certain eligibility criteria. Eligible employees of Power, PSE&G, Energy Holdings and Services participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG s two defined contribution plans described below.

In September 2006, the FASB issued SFAS 158, which became effective prospectively for periods ending after December 15, 2006. In accordance with SFAS 158, PSEG, Power and PSE&G were required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions were measured as of December 31, 2007 in compliance with SFAS 158 and in accordance with customary practice of each PSEG company prior to the issuance of SFAS 158. For under funded plans, the liability is equal to the difference between the plan s benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, the statement requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income, a separate component of Stockholder s Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs were recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses, prior service costs and transition obligations arising from the adoption of the preceding pension and OPEB accounting standards, which have not been expensed.

Prior accounting guidance required that unrecognized costs be presented in a footnote to the financial statements as part of a reconciliation of a plan s funded status to amounts recorded in the financial statements. The unrecognized costs are amortized as a component of net periodic pension or OPEB expense. Under the new standard, for Power, the charge to Other Comprehensive Income will be amortized and recorded as net periodic pension cost in the Statement of Operations. For PSE&G, the Regulatory Asset will be amortized and recorded as net periodic pension cost in the Statement of Operations.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2007 and 2006. It also provides the funded status of the plans and the amounts recognized and amounts not recognized in the Statement of Financial Position at the end of both years.

Pension Benefits

Other Benefits

2007

2006

2007

2006

(Millions)

Change in Benefit Obligation:

Benefit Obligation at Beginning of Year

$

3,723

$

3,759

$

1,242

$

1,219

Service Cost

83

86

16

18

Interest Cost

217

211

73

68

Actuarial Gain

(209

)

(127

)

(100

)

(1

)

Gross Benefits Paid

(213

)

(206

)

(70

)

(67

)

Medicare Subsidy Receipts

5

5

Benefit Obligation at End of Year

$

3,601

$

3,723

$

1,166

$

1,242

Change in Plan Assets:

Fair Value of Assets at Beginning of Year

$

3,390

$

3,105

$

154

$

123

Actual Return on Plan Assets

191

437

9

19

Employer Contributions

22

54

65

74

Gross Benefits Paid

(213

)

(206

)

(70

)

(67

)

Medicare Subsidy Receipts

5

5

Fair Value of Assets at End of Year

$

3,390

$

3,390

$

163

$

154

Funded Status:

Funded Status (Plan Assets less Benefit Obligation)

$

(211

)

$

(333

)

$

(1,003

)

$

(1,088

)

Amounts Recognized in the Statement of Financial Position:

Current Accrued Benefit Cost

$

(8

)

$

(7

)

$

$

Noncurrent Accrued Benefit Cost

(203

)

(326

)

(1,003

)

(1,088

)

Amounts Recognized.

$

(211

)

$

(333

)

$

(1,003

)

$

(1,088

)

Additional Amounts Recognized in Accumulated Other Comprehensive Income, Regulated Assets and Deferred Assets:

Net Transition Obligation

$

$

$

112

$

139

Prior Service Cost

41

51

109

122

Net Actuarial Loss

489

622

78

180

Total

$

530

$

673

$

299

$

441

The pension benefits table above provides information relating to the funded status of all qualified and nonqualified pension plans and other postretirement benefit plans on an aggregate basis. The nonqualified pension plans are partially funded with Rabbi Trusts. In accordance with SFAS 87, the plan assets in the table above do not include the assets held in the Rabbi Trusts. Including the $158 million of assets in the Rabbi Trusts as of December 31, 2007, PSEG has funded approximately 98.5% of its projected benefit obligation. The fair values of the Rabbi Trust assets are included on the Consolidated Balance Sheets. For additional information see Rabbi Trusts below.

Accumulated Benefit Obligation

The accumulated benefit obligation for all PSEG s defined benefit pension plans was $3.1 billion as of December 31, 2007 and $3.2 billion as of December 31, 2006.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides the components of net periodic benefit cost for the years ended December 31, 2007, 2006 and 2005:

Pension Benefits

Other Benefits

2007

2006

2005

2007

2006

2005

(Millions)

Components of Net Periodic Benefit Cost:

Service Cost

$

83

$

86

$

90

$

16

$

18

$

18

Interest Cost

217

211

206

73

68

62

Expected Return on Plan Assets

(289

)

(265

)

(249

)

(14

)

(11

)

(9

)

Amortization of Net

Transition Obligation

28

28

27

Prior Service Cost

10

11

16

13

13

9

Actuarial Loss

22

54

46

7

8

2

Net Periodic Benefit Cost

$

43

$

97

$

109

$

123

$

124

$

109

Components of Total Benefit Expense:

Net Periodic Benefit Cost

$

43

$

97

$

109

$

123

$

124

$

109

Effect of Regulatory Asset

19

19

19

Total Benefit Expense Including Effect of Regulatory Asset

$

43

$

97

$

109

$

142

$

143

$

128

The following table provides the changes recognized in Other Comprehensive Income:

Pension

OPEB

2007

2006

2007

2006

(Millions)

Net Actuarial Gain in current period

$

(111

)

$

N/A

$

(95

)

$

N/A

Amortization of Net Actuarial Gain

(22

)

N/A

(7

)

N/A

Amortization of Prior Service Credit

(10

)

N/A

(13

)

N/A

Amortization of Transition Asset

N/A

(28

)

N/A

Total

$

(143

)

$

N/A

$

(143

)

$

N/A

Amounts that are expected to be amortized from Accumulated Other Comprehensive Income/Loss into Net Periodic Benefit Cost in 2008 are as follows:

	Pension Benefits	Other Benefits
	2008	2008
(Millions)		
Actuarial Loss (Gain)	$ 13	$ (1)

Prior Service Cost

$

9

$

13

Transition Obligation

$

$

27

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

Pension Benefits

Other Benefits

2007

2006

2005

2007

2006

2005

Weighted-Average Assumptions Used to Determine

Benefit Obligations as of December 31:

Discount Rate

6.50

%

6.00

%

5.75

%

6.50

%

6.00

%

5.75

%

Rate of Compensation Increase

4.69

%

4.69

%

4.69

%

4.69

%

4.69

%

4.69

%

Weighted-Average Assumptions Used to Determine Net

Periodic Benefit Cost for Years Ended December 31:

Discount Rate

6.00

%

5.75

%

6.00

%

6.00

%

5.75

%

6.00

%

Expected Return on Plan Assets

8.75

%

8.75

%

8.75

%

8.75

%

8.75

%

8.75

%

Rate of Compensation Increase

4.69

%

4.69

%

4.69

%

4.69

%

4.69

%

4.69

%

Assumed Health Care Cost Trend Rates as of December 31:

Administrative Expense

5.00

%

5.00

%

5.00

%

Dental Costs

6.00

%

6.00

%

6.00

%

Pre-65 Medical Costs

Immediate Rate

8.50

%

9.50

%

9.50

%

Ultimate Rate

5.00

%

5.00

%

5.00

%

Year Ultimate Rate Reached

2012

2012

2011

Post-65 Medical Costs

Immediate Rate

9.50

%

10.50

%

10.50

%

Ultimate Rate

5.00

%

5.00

%

5.00

%

Year Ultimate Rate Reached

2013

2013

2012

Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs:

(Millions)

Total of Service Cost and Interest Cost

$

11

$

11

$

11

Postretirement Benefit Obligation

$

121

$

134

$

132

Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs:

Total of Service Cost and Interest Cost

$

(9

)

$

(9

)

$

(9

)

Postretirement Benefit Obligation

$

(101

)

$

(111

)

$

(109

)

Plan Assets

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

Investments

As of December 31,

2007

2006

Equity Securities

62

%

63

%

Fixed Income Securities

31

%

29

%

Real Estate Assets

6

%

6

%

Other Investments

1

%

2

%

Total Percentage

100

%

100

%

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop an optimal portfolio, which is designed to produce the maximum return opportunity per unit of risk. In 2007, PSEG completed its latest asset/liability study. The results from the study indicated that, in order to achieve the optimal risk/return portfolio, target allocations of 62% equity securities, 30% fixed income securities, 5% real estate investments, and 3% for other investments should be maintained. Derivative financial instruments are used by the plans investment managers primarily to rebalance the fixed income/equity allocation of the portfolio and hedge the currency risk component of the foreign investments.

The expected long-term rate of return on plan assets was 8.75% as of December 31, 2007. For 2008, the expected long-term rate of return on plan assets will remain at 8.75%. This expected return was determined

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

based on the study discussed above and considered the plans historical annualized rate of return since inception of the plans, which was an annualized return of 10.2%.

Plan Contributions

PSEG may contribute up to $50 million into its qualified pension plans and postretirement healthcare plan for calendar year 2008.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants. Postretirement benefit payments are shown both gross and net of the federal subsidy expected for prescription drugs under the Medicare Prescription Drug Improvement and Modernization Act of 2003. The Act provides a nontaxable federal subsidy to employers that provide retiree prescription drug benefits that are equivalent to the benefits of Medicare Part D.

Year

Pension Benefits

Other Benefits

Gross OPEB

Medicare Subsidy

Net OPEB

(Millions)

2008

$

213

$

76

$

(5

)

$

71

2009

216

79

(5

)

74

2010

221

82

(6

)

76

2011

227

84

(6

)

78

2012

234

86

(7

)

79

2013 2017

1,314

443

(39

)

404

Total

$

2,425

$

850

$

(68

)

$

782

Rabbi Trusts

PSEG maintains certain unfunded, nonqualified benefit plans for which certain assets have been set aside in grantor trusts commonly known as Rabbi Trusts to provide supplemental retirement and deferred compensation benefits to certain of its and its subsidiaries key employees and directors.

Effective January 1, 2003, PSEG began accounting for the assets in the Rabbi Trusts under SFAS 115. PSEG classifies investments in the Rabbi Trusts as available-for-sale under SFAS 115. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trusts:

As of December 31, 2007

Cost

Gross
Unrealized
Gains

Gross
Unrealized
Losses

Estimated
Fair
Value

(Millions)

Equity Securities

$

12

$

4

$

$

16

Debt Securities

Government Obligations.

90

4

94

Other Debt Securities

30

2

32

Total Debt Securities

120

6

126

Other Securities.

16

16

Total Available-for-Sale Securities

$

148

$

10

$

$

158

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

As of December 31, 2006

Cost

Gross Unrealized Gains

Gross Unrealized Losses

Estimated Fair Value

(Millions)

Equity Securities

$

12

$

3

$

$

15

Debt Securities

Government Obligations.

85

85

Other Debt Securities

28

1

29

Total Debt Securities

113

1

114

Other Securities.

15

15

Total Available-for-Sale Securities

$

140

$

4

$

$

144

In 2007 other-than-temporary impairments of $1 million were recognized on the debt securities Investments of the Rabbi Trusts.

Years Ended December 31,

2007

2006

2005

(Millions)

Proceeds from Sales

$

40

$

30

$

100

Gross Realized Gains

$

1

$

$

Gross Realized Losses.

$

(2

)

$

(1

)

$

(1

)

Net realized losses of $1 million were recognized in Other Deductions on PSEG s Consolidated Statement of Operations for the year ended December 31, 2007. The available-for-sale debt securities held as of December 31, 2007, had the following maturities: $6 million less than one year, $29 million one to five years, $25 million five to 10 years, $9 million 10 to 15 years, $3 million 15 to 20 years, and $54 million over 20 years. The cost of these securities was determined on the basis of specific identification.

The estimated fair value of the Rabbi Trusts related to PSEG, Power and PSE&G are detailed as follows:

As of December 31,

2007

2006

(Millions)

Power

$

45

$

43

PSE&G

57

54

Other

56

47

Total

$

158

$

144

401(k) Plans

PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act (ERISA) defined contribution plans. Eligible represented employees of PSE&G, Power and Services participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSE&G, Power, Energy Holdings and Services participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans. Employee contributions up to 7% for Savings Plan participants and up to 8% for Thrift Plan participants are matched with Employer

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

contributions of cash equal to 50% of such employee contributions. The amount paid for Employer matching contributions to the plans for PSEG, Power and PSE&G are detailed as follows:

Thrift Plan and Savings Plan

Years Ended December 31,

2007

2006

2005

(Millions)

Power

$

9

$

8

$

9

PSE&G

15

15

15

Other

4

4

4

Total Employer Matching Contributions

$

28

$

27

$

28

Pension costs and OPEB costs for PSEG, Power and PSE&G are detailed as follows:

Pension Benefits

Other Benefits

Years Ended December 31,

Years Ended December 31,

2007

2006

2005

2007

2006

2005

(Millions)

Power

$

12

$

30

$

33

$

16

$

16

$

12

PSE&G

19

49

55

121

121

112

Other.

12

18

21

5

6

4

Total Benefit Expense

$

43

$

97

$

109

$

142

$

143

$

128

Note 17. Stock Based Compensation

PSEG

As approved at the Annual Meeting of Stockholders in 2004, PSEG s 2004 Long-Term Incentive Plan (LTIP) replaced the prior 1989 LTIP and 2001 LTIP. The 2004 LTIP is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance shares, restricted stock, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIPs are non-qualified options to purchase shares of PSEG s common stock, restricted stock awards and performance unit awards. Under the 2004 LTIP through December 31, 2007 stock options and restricted stock have been granted.

The 2004 LTIP currently provides for the issuance of equity awards with respect to approximately 26 million shares of common stock. As of December 31, 2007, there were approximately 24 million shares available for future awards under the 2004 LTIP.

Stock Options

Under the 2004 LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees of PSEG and its subsidiaries selected by the Organization and Compensation Committee of PSEG s Board of Directors, the plan s administrative committee (Committee). Option awards are granted with an exercise price equal to the market price of PSEG s common stock at the grant date. The options generally vest based on three to five years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change- in-control, retirement, death or disability. Options are exercisable over a period of time designated by the Committee (but not prior to one year or longer than 10 years from the date of grant) and are subject to such other terms and conditions as the Committee determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the Committee, by delivering previously acquired shares of PSEG common stock.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Restricted Stock

Under the 2004 LTIP, PSEG has granted restricted stock awards to officers and other key employees. These shares are subject to risk of forfeiture until vested by continued employment. Restricted stock generally vests annually over three or four years, but is considered outstanding at the time of grant, as the recipients are entitled to dividends and voting rights. Vesting may be accelerated upon certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Restricted Stock Units

Under the 2004 LTIP, PSEG has granted restricted stock unit awards to officers and certain other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until vested, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. The restricted stock units generally vest annually over four years, and distributions are made in shares of common stock. Vesting may be accelerated upon certain events, such as change-in-control (unless substituted with an equity award of equal value), retirement, death or disability.

Performance Units

Under the 2004 LTIP, performance units were granted to certain key executives, which provide for payment in shares of PSEG common stock based on achievement of certain financial goals over the three-year period from 2004 through 2006. In January and December 2007, additional performance units were granted to certain key executives that provide for payment in shares of PSEG common stock based on achievement of certain financial goals over specific three-year periods between 2007 through 2011. The payout varies from 0% to 200% of the number of performance units granted depending on PSEG s performance compared to the performance of other companies in multiple peer groups. The performance units are credited with dividend equivalents in an amount equal to dividends paid on PSEG common stock up until January 1, 2012. Vesting may be accelerated upon certain events such as change-in-control, retirement, death or disability.

Stock-Based Compensation

Effective January 1, 2006, PSEG adopted SFAS No. 123R, Stock-Based Payment, revised 2004 (SFAS 123R). As a result, all outstanding unvested stock options as of January 1, 2006 are being expensed based on their grant date fair values, which were determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

Prior to the adoption of SFAS 123R, PSEG recognized compensation expense for restricted stock over the vesting period based on the grant date fair market value of the shares. PSEG will continue to recognize compensation expense over the vesting term.

Also prior to the adoption of SFAS 123R, PSEG recognized compensation expense for performance units. The fair value of each performance unit was based on the grant date fair value of PSEG common stock. The accrual of compensation cost was based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. The current accrual is estimated at 100% of the original grant. The accrual is adjusted for subsequent changes in the estimated or actual outcome.

PSEG

2007

2006

2005

(Millions)

Compensation Cost included in Operation and Maintenance Expense (A)

$

22

$

17

$

6

Income Tax Benefit Recognized on Consolidated Statement of Operations

$

9

$

7

$

3

(A) Compensation cost capitalized as part of Property, Plant and Equipment was less than $1 million for each of the years ended December 31, 2007, 2006 and 2005.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Of the total compensation cost for the years ended December 31, 2006, $2 million, after-tax, was primarily due to expensing stock options under SFAS 123R in 2006 and increased stock option activity. There was no impact on basic and diluted earnings per share from the implementation of SFAS 123R because there were a relatively small number of outstanding unvested stock options as of the implementation date.

Prior to the adoption of SFAS 123R, PSEG presented all tax benefits for deductions resulting from the exercise of share-based compensation as operating cash flows on the Consolidated Statement of Cash Flows. SFAS 123R requires the benefits of tax deductions in excess of the taxes expensed on recognized compensation cost to be reported as financing cash flows. There was $18 million, $15 million and $30 million of excess tax benefits included as a financing cash inflow on the Consolidated Statement of Cash Flow for the years ended December 31, 2007, 2006 and 2005, respectively. Total cash flow will remain unchanged from what would have been reported under prior accounting rules.

Prior to the adoption of SFAS 123R, PSEG recognized the compensation cost of stock based awards issued to retirement eligible employees that fully or partially vest upon an employee s retirement over the nominal vesting period of performance, and recognized any remaining compensation cost at the date of retirement. In accordance with SFAS 123R, PSEG recognizes compensation cost of awards issued after January 1, 2006 over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.

Changes in stock options for 2007 are summarized as follows:

2007

Options

Weighted Average Exercise Price

Beginning of year

3,632,004

$

21.32

Granted.

1,569,300

38.37

Exercised

(2,229,004

)

22.15

Canceled.

(281,064

)

24.42

End of year

2,691,236

$

30.24

Exercisable at end of year

1,259,936

$

21.41

Options

Weighted
Average
Remaining
Contractual
Term

Aggregate
Intrinsic
Value

Outstanding at December 31, 2007

4.4

$

50,796,273

Exercisable at December 31, 2007

4.7

$

34,911,832

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model. The following weighted average assumptions were used for grants in 2004 and 2007:

2004

2007 options

January, March, June

December

Expected Volatility

26.74

%

24.87

%

24.60

%

Risk-Free Interest Rate

3.09

%

4.72

%

3.78

%

Expected Life (Years)

4

6.25

6.25

Weighted Average Dividend Yield

5.00

%

3.46

%

2.40

%

The intrinsic value of options is the difference between the current market price and the exercise price. Activity for options exercised is shown below:

2007

2006

2005

(Millions)

Total Intrinsic value of options exercised

$

43

$

56

$

72

Cash Received from options exercised

$

49

$

86

$

141

Tax benefit realized from options exercised

$

14

$

15

$

30

163

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Approximately two million options vested during the year ended December 31, 2007 and approximately one million options vested during each of the years ended December 31, 2006 and 2005. The weighted average fair value per share for options vested during the years ended December 31, 2007, 2006 and 2005 was $24.93, $20.58 and $19.13 respectively.

As of December 31, 2007, there was approximately $10 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted average period of 20 months.

Restricted Stock Information

Changes in restricted stock for the years ended December 31, 2007 are summarized as follows:

Shares

Weighted Average Grant Date Fair Value

Weighted Average Remaining Contractual

Term

Aggregate
Intrinsic
Value

Outstanding at January 1, 2007

635,446

$

15.35

Granted.

426,210

37.18

Vested

(477,130

)

15.06

Canceled.

(24,762

)

27.89

Outstanding at December 31, 2007

559,764

$

31.67

2.2

$

23,817,011

The weighted average grant date fair value per share was $37.18, $32.94 and $28.73 for restricted stock awards granted during the years ended December 31, 2007, 2006 and 2005, respectively.

The total intrinsic value of restricted stock vested during the years ended December 31, 2007 and 2006 was $4 million and $2 million, respectively.

As of December 31, 2007, there was approximately $12 million of unrecognized compensation cost related to restricted stock, which is expected to be recognized over a weighted average period of 2 years.

Restricted Stock Units

On December 18, 2007, 66,100 restricted stock units were issued to officers and certain key employees at $48.21 per share, vesting over a period of four years. As of December 31, 2007, there was approximately $3 million of unrecognized compensation cost related to the restricted stock units, which is expected to be recognized over a weighted average period of four years.

Performance Units Information

Performance Unit information for 2007 is detailed below:

Shares

Intrinsic Value per share as of December 31, 2007

Intrinsic Value as of December 31, 2007

Outstanding at January 1, 2007

$

Granted

480,490

Canceled

(2,200

)

Outstanding at December 31, 2007

478,290

$

49.12

$

23,462,256

During 2007, approximately 280,000 performance units were issued with an incentive period of 2007-2009 and approximately 200,000 units were issued with an incentive period of 2008-2011. Approximately 7,000 dividend equivalents accrued on the performance units during the year.

Outside Directors

Through 2006, each director who was not an officer of PSEG or its subsidiaries and affiliates was paid an annual retainer of $50,000. Pursuant to the Compensation Plan for Outside Directors, 50% of the annual retainer was paid in PSEG common stock. PSEG also maintained a Stock Plan for Outside Directors (Stock

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Plan) pursuant to which directors of PSEG who are not employees of PSEG or its subsidiaries received a restricted stock award, currently 2,000 shares per year, for each year of service as a director. The restrictions on the stock granted under the Stock Plan provide that the shares are subject to forfeiture if the director leaves service at any time prior to the Annual Meeting of Stockholders following his or her 72nd birthday. This restriction would be deemed to have been satisfied if the director s service was terminated after a change-in-control as defined in the Stock Plan or if the director was to die in office. PSEG also has the ability to waive this restriction for good cause shown. The fair value of these shares is recorded as compensation expense on the Consolidated Statements of Operations. Compensation expense for the Stock Plan for each of the years ended December 31, 2006 and 2005, respectively was $1 million.

For 2007, a new Director Compensation plan was approved. Annually on May 1, each board member will be awarded stock units based on amount of annual compensation to be paid and the May 1 closing price of PSEG Common Stock. Dividend equivalents will be credited quarterly and will commence upon the director leaving the board. Compensation expense for the Stock Plan for the year ended December 31, 2007 was approximately was $1 million.

Employee Stock Purchase Plan

PSEG maintains an employee stock purchase plan for all eligible employees of PSEG and its subsidiaries. Under the plan, shares of PSEG common stock may be purchased at 95% of the fair market value through payroll deductions. In any year, employees may purchase shares having a value not exceeding 10% of their base pay. During the years ended December 31, 2007, 2006 and 2005, employees purchased 88,656, 120,702 and 153,458 shares at an average price of $39.64, $30.82 and $27.00 per share, respectively. As of December 31, 2007, 3.6 million shares were available for future issuance under this plan.

Note 18. Financial Information by Business Segment

Basis of Organization

PSEG, Power and PSE&G

The reportable segments were determined by management in accordance with SFAS No. 131, Disclosures About Segments of an Enterprise and Related Information (SFAS 131). These segments were determined based on how management measures performance based on segment Net Income, as illustrated in the following table, and how it allocates resources to each business.

Power

Power earns revenues by selling energy, capacity and ancillary services on a wholesale basis under contract to power marketers and to load serving entities and by bidding energy, capacity and ancillary services into the markets for these products. Power also enters into trading contracts for energy, capacity, firm transmission rights, gas, emission allowances and other energy-related contracts to optimize the value of its portfolio of generating assets and its electric and gas supply obligations.

PSE&G

PSE&G earns revenue from its tariffs, under which it provides electric transmission and electric and gas distribution services to residential, commercial and industrial customers in New Jersey. The rates charged for electric transmission are regulated by the FERC while the rates charged for electric and gas distribution are regulated by the BPU. Revenues are also earned from several other activities such as sundry sales, the appliance service business, wholesale transmission services and other miscellaneous services.

Global

Global primarily earns revenues from its domestic investments in and operation of projects in the generation of energy. The generation plants sell power under long-term agreements as well as on a merchant basis Revenues include revenues of consolidated investments. Gains and losses on sales of investments are typically recognized in revenues. Global has sold the majority of its previously owned international generation and distribution businesses. Global s largest remaining international investment is in SAESA, which has been reclassified to discontinued operations following the announcement that Global began exploring the sale of that investment in December 2007.

Resources

Resources earns revenues from its passive investments in leveraged leases, limited partnerships, leveraged buyout funds and marketable securities. Approximately 96% of Resources investments are in leveraged leases. Demand Side Management investments earn revenues primarily from monthly payments from utilities, representing shared electricity savings from the installation of energy efficient equipment. Resources operates both domestically and internationally; however, revenues from all international investments are denominated in U.S. dollars. Gains and losses on sales of investments are typically recognized in revenues.

Other

PSEG s other activities include amounts applicable to PSEG (parent corporation) and Energy Holdings (parent company), and intercompany eliminations, primarily relating to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 21. Related-Party Transactions. The net losses primarily relate to financing and certain administrative and general cost.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Information related to the segments of PSEG and its subsidiaries is detailed below:

Power

PSE&G

Resources

Global

Other

Consolidated
Total

(Millions)

For the Year Ended December 31, 2007:

Total Operating Revenues

$

6,796

$

8,493

$

157

$

795

$

(3,388

)

$

12,853

Depreciation and Amortization

140

591

11

27

14

783

Income from Equity Method Investments

1

114

1

116

Operating Income

1,680

957

128

314

10

3,089

Interest Income

21

10

8

(3

)

36

Interest Expense

159

332

31

109

98

729

Income (Loss) Before Income Taxes

1,590

637

97

211

(156

)

2,379

Income Tax Expense (Benefit)

641

257

39

182

(59

)

1,060

Income (Loss) From Continuing Operations

949

380

58

31

(99

)

1,319

(Loss) Income from Discontinued Operations, net of Tax (including (Loss) Gain)

(8

)

24

16

Net Income (Loss)

941

380

58

55

(99

)

1,335

Segment Earnings (Loss)

941

376

58

55

(95

)

1,335

Gross Additions to Long-Lived Assets

$

715

$

570

$

1

$

36

$

26

$

1,348

As of December 31, 2007:

Total Assets

$

8,428

$

14,637

$

2,992

$

2,334

$

1

$

28,392

Investments in Equity Method Subsidiaries

$

14

$

$

$

208

$

$

222

For the Year Ended December 31, 2006:

Total Operating Revenues

$

6,057

$

7,569

$

174

$

772

$

(2,810

)

$

11,762

Depreciation and Amortization

140

620

11

22

18

811

Income from Equity Method Investments

120

120

Operating Income (Loss)

960

772

142

(22

)

(6

)

1,846

Interest Income

13

11

6

6

36

Interest Expense

148

346

51

115

131

791

Income (Loss) Before Income Taxes

878

448

85

(135

)

(137

)

1,139

Income Tax Expense (Benefit)

363

183

22

(52

)

(56

)

460

Income (Loss) From Continuing Operations

515

265

63

(84

)

(80

)

679

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

(239

)

298

1

60

Net Income (Loss)

276

265

63

214

(79

)

739

Segment Earnings (Loss)

276

261

63

214

(75

)

739

Gross Additions to Long-Lived Assets

$

418

$

528

$

1

$

62

$

6

$

1,015

As of December 31, 2006:

Total Assets

$

8,128

$

14,553

$

2,969

$

3,095

$

(193

)

$

28,552

Investments in Equity Method Subsidiaries

$

16

$

$

5

$

818

$

$

839

For the Year Ended December 31, 2005:

Total Operating Revenues

$

6,027

$

7,514

$

247

$

731

$

(2,670

)

$

11,849

Depreciation and Amortization

114

553

7

22

18

714

(Loss) Income from Equity Method Investments.

(1

)

125

124

Operating Income (Loss)

708

913

208

211

(28

)

2,012

Interest Income

11

11

8

4

34

Interest Expense

100

342

73

121

130

766

Income (Loss) Before Income Taxes

752

583

130

86

(165

)

1,386

Income Tax Expense (Benefit)

318

235

38

23

(65

)

549

Income (Loss) From Continuing Operations

434

348

92

63

(100

)

837

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

(226

)

67

(159

)

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

(16

)

(1

)

(17

)

Net Income (Loss)

192

348

92

130

(101

)

661

Segment Earnings (Loss)

192

344

92

127

(94

)

661

Gross Additions to Long-Lived Assets

$

476

$

498

$

3

$

64

$

12

$

1,053

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Geographic information for PSEG is disclosed below. The foreign assets and operations noted below relate solely to Energy Holdings:

Revenues

Assets(A)

December 31,

December 31,

2007

2006

2005

2007

2006

(Millions)

United States

$

12,619

$

11,652

$

11,736

$

25,438

$

24,844

Foreign Countries

234

110

113

2,954

3,708

Total

$

12,853

$

11,762

$

11,849

$

28,392

$

28,552

Identifiable assets in foreign countries include:

Chile(B)

$

1,161

$

1,441

Netherlands

1,221

1,231

Peru

462

Austria

196

191

Italy

162

149

Other

214

234

Total

$

2,954

$

3,708

(A)

Total assets are net of foreign currency translation adjustment of $108 million (after-tax) as of December 31, 2007 and $111 million (after-tax) as of December 31, 2006

(B)

2007 includes the assets of discontinued operations for SAESA and Electroandes. 2006 also includes the equity investment in Chilquinta which was sold in 2007. See Note 4. Discontinued Operations, Dispositions, Acquisitions and Impairments.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 19. Property, Plant and Equipment and Jointly-Owned Facilities

Information related to Property, Plant and Equipment as of December 31, 2007 and 2006 is detailed below:

Power

PSE&G

Other

PSEG
Consolidated

(Millions)

<u>2007</u>

Generation:

Fossil Production

$

4,463

$

$

741

$

5,204

Nuclear Production

724

724

Nuclear Fuel in Service

550

550

Construction Work in Progress

767

767

Total Generation

6,504

741

7,245

Transmission and Distribution:

Electric Transmission

1,562

1,562

Electric Distribution

5,295

5,295

Gas Transmission

88

88

Gas Distribution

4,033

4,033

Construction Work in Progress

54

54

Plant Held for Future Use

8

8

Other

430

430

Total Transmission and Distribution

11,470

11,470

Other

61

61

473

595

Total

$

6,565

$

11,531

$

1,214

$

19,310

2006

Generation:

Fossil Production

$

4,342

$

$

708

$

5,050

Nuclear Production

625

625

Nuclear Fuel in Service

479

479

Construction Work in Progress

361

361

Total Generation

5,807

708

6,515

Transmission and Distribution:

Electric Transmission

1,402

1,402

Electric Distribution

5,058

5,058

Gas Transmission

88

88

Gas Distribution

3,872

3,872

Construction Work in Progress

58

58

Plant Held for Future Use

24

24

Other

455

455

Total Transmission and Distribution

10,957

10,957

Other

61

104

457

622

Total

$

5,868

$

11,061

$

1,165

$

18,094

Power and PSE&G

Power and PSE&G have ownership interests in and are responsible for providing their share of the necessary financing for the following jointly-owned facilities. All amounts reflect the share of Power s and PSE&G s jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Ownership Interest

Plant

Accumulated Depreciation

(Millions)

December 31, 2007

Power:

Coal Generating

Conemaugh

22.50

%

$

218

$

109

Keystone

22.84

%

$

216

$

87

Nuclear Generating

Peach Bottom

50.00

%

$

234

$

125

Salem

57.41

%

$

612

$

191

Nuclear Support Facilities

Various

$

127

$

20

Pumped Storage Facilities

Yards Creek

50.00

%

$

29

$

22

Merrill Creek Reservoir.

13.91

%

$

1

$

PSE&G:

Transmission Facilities

Various

$

117

$

56

Linden SNG Plant

90.00

%

$

5

$

6

December 31, 2006

Power:

Coal Generating

Conemaugh

22.50

%

$

213

$

105

Keystone

22.84

%

$

189

$

84

Nuclear Generating

Peach Bottom

50.00

%

$

223

$

121

Salem

57.41

%

$

541

$

172

Nuclear Support Facilities

Various

$

119

$

15

Pumped Storage Facilities

Yards Creek

50.00

%

$

29

$

22

Merrill Creek Reservoir.

13.91

%

$

1

$

PSE&G:

Transmission Facilities

Various

$

116

$

54

Linden SNG Plant

90.00

%

$

5

$

6

Power

Power holds undivided ownership interests in the jointly-owned facilities above, excluding related nuclear fuel and inventories. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power s share of expenses for the jointly-owned facilities is included in the appropriate expense category.

Power s subsidiary, Nuclear, co-owns Salem and Peach Bottom with Exelon Generation. Nuclear is the owner-operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners reviews/approves major planning, financing and budgetary (capital and operating) decisions. Operating decisions within the above guidelines are made by the owner-operator.

Reliant Energy, Inc. is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by all co-owners makes all planning, financing and budgetary (capital and operating) decisions. Operating decisions within the above guidelines are made by Reliant Energy, Inc.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. First Energy Corporation is also a co-owner and the operator of this facility. First Energy submits separate capital and Operations and Maintenance budgets, subject to the approval of Power.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Reservoir is the owner-operator of this facility. The operator submits separate capital and Operations and Maintenance budgets, subject to the approval of the non-operating owners.

All owners receive revenues, Operations and Maintenance and capital allocations based on their ownership percentages. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Note 20. Selected Quarterly Data (Unaudited)

PSEG, Power and PSE&G

The information shown below, in the opinion of PSEG, Power and PSE&G includes all adjustments, consisting only of normal recurring accruals, necessary to fairly present such amounts.

Calendar Quarter Ended

March 31,

June 30,

September 30,

December 31,

2007

2006

2007

2006

2007

2006

2007

2006

3,508

(Millions, where applicable)

PSEG Consolidated:

Operating Revenues

$

3,508

$

3,373

$

2,718

$

2,470

$

3,356

$

3,217

$

3,271

$

2,702

Operating Income

728

507

617

161

980

781

764

397

Income (Loss) from Continuing Operations

321

197

283

(15

)

490

364

225

133

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

8

6

(8

)

224

16

10

(180

)

Net Income (Loss)

329

203

275

209

506

374

225

(47

)

Earnings Per Share:

Basic:

Income (Loss) from Continuing Operations

0.63

0.39

0.56

(0.03

)

0.96

0.72

0.44

0.26

Net Income (Loss)

0.65

0.40

0.54

0.42

0.99

0.74

0.44

(0.09

)

Diluted:

Income from Continuing Operations

0.64

0.39

0.56

(0.03

)

0.46

0.72

0.44

0.26

Net Income (Loss)

0.65

0.40

0.54

0.41

0.99

0.79

0.44

(0.09

)

Weighted Average Common Shares Outstanding:

Basic

506

502

507

503

509

503

509

505

Diluted

507

504

508

504

509

505

510

506

Calendar Quarter Ended

March 31,

June 30,

September 30,

December 31,

2007

2006

2007

2006

2007

2006

2007

2006

(Millions)

Power:

Operating Revenues

$

2,149

$

1,967

$

1,305

$

1,129

$

1,580

$

1,455

$

1,762

$

1,506

Operating Income

389

217

336

162

600

391

355

190

Income from Continuing Operations

219

121

187

85

338

207

205

102

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

(6

)

(9

)

(3

)

(8

)

1

(2

)

(220

)

Net Income (Loss)

213

112

184

77

339

205

205

(118

)

Calendar Quarter Ended

March 31,

June 30,

September 30,

December 31,

2007

2006

2007

2006

2007

2006

2007

2006

(Millions)

PSE&G:

Operating Revenues

$

2,486

$

2,293

$

1,748

$

1,490

$

2,106

$

1,971

$

2,153

$

1,815

Operating Income

308

225

184

136

265

237

200

174

Income from Continuing Operations

132

78

63

34

107

88

78

65

Net Income

132

78

63

34

107

88

78

65

Earnings Available to PSEG

131

77

62

33

106

87

77

64

Note 21. Related-Party Transactions

The majority of the following discussion relates to intercompany transactions, which are eliminated during the PSEG consolidation process in accordance with GAAP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

BGSS and BGS Contracts

Power and PSE&G

PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G s BGSS and other contractual requirements through March 31, 2012 and year-to-year thereafter.

Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

The amounts which Power charged to PSE&G for BGS and BGSS are presented below:

Billings for the Years Ended December 31,

2007

2006

2005

(Millions)

BGS

$

1,163

$

793

$

497

BGSS

$

2,208

$

1,995

$

2,127

As of December 31, 2007 and 2006, Power had receivables from PSE&G of $451 million and $367 million, respectively, primarily related to the BGS and BGSS contracts. These transactions were properly recognized on each company s stand-alone financial statements and were eliminated when preparing PSEG s Consolidated Financial Statements.

In addition, as of December 31, 2007 and 2006, PSE&G had a payable to Power of $55 million and $177 million, respectively, related to gas supply hedges Power entered into for BGSS. For additional information, see Note 12. Commitments and Contingent Liabilities.

Services

Power and PSE&G

Services provides and bills administrative services to Power and PSE&G. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies. The billings for administrative services and payables are presented below:

Services Billings for the Years Ended December 31,

Payable to Services as of December 31,

2007

2006

2005

2007

2006

(Millions)

Power

$

144

$

137

$

154

$

24

$

21

PSE&G

$

238

$

215

$

209

$

57

$

41

These transactions were properly recognized on each company s stand-alone financial statements and were eliminated when preparing PSEG s Consolidated Financial Statements. PSEG, PSE&G, Power and Energy Holdings believe that the costs of services provided by Services approximate market value for such services.

Tax Sharing Agreement

Power and PSE&G

PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power and PSE&G had payables to PSEG related to taxes as follows:

Payable to PSEG as of December 31,

2007

2006

(Millions)

Power

$

43

$

28

PSE&G

$

5

$

63

In addition to these tax payable amounts, as of December 31, 2007, Power had an $8 million current receivable from PSEG and PSE&G had a $3 million current payable to PSEG related to unrecognized tax positions. PSEG and its subsidiaries adopted FIN 48 effective January 1, 2007, which prescribes a model for how a company should recognize, measure, present and disclose in its financial statements uncertain tax positions that it has taken or expects to take on a tax return. See Note 2. Recent Accounting Standards and Note 15. Income Taxes for additional information.

Affiliate Loans and Advances

Power

As of December 31, 2007 and December 31, 2006, Power had a demand note payable to PSEG of $238 million and $54 million, respectively, for short-term funding needs. Interest Income and Interest Expense relating to these short term funding activities was immaterial.

PSE&G and Services

As of each of December 31, 2007 and 2006, PSE&G had advanced working capital to Services of $33 million. The amount is included in Other Noncurrent Assets on PSE&G s Consolidated Balance Sheets.

Power and Services

As of each of December 31, 2007 and 2006, Power had advanced working capital to Services of $17 million. The amount is included in Other Noncurrent Assets on Power s Consolidated Balance Sheets.

Other

PSEG and Power

As of December 31, 2007 and 2006, PSEG had net receivables from Power of $5 million and less than $1 million, respectively, related to amounts that Power had collected on PSEG s behalf.

PSEG and PSE&G

As of December 31, 2007 and 2006, PSE&G had net receivables from PSEG of $11 million and $3 million, respectively, related to amounts that PSEG had collected on PSE&G s behalf.

Changes in Capitalization

Power

Power paid dividends to PSEG totaling $1.075 billion to PSEG during 2007.

PSE&G

PSE&G paid common stock dividends of $200 million to PSEG in both 2007 and 2006.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 22. Guarantees of Debt

Each series of Power s Senior Notes and Pollution Control Notes is fully and unconditionally and jointly and severally guaranteed by Fossil, Nuclear and ER&T.

The following table presents condensed financial information for the guarantor subsidiaries as well as Power s non-guarantor subsidiaries as of December 31, 2007 and 2006 and for the years ended December 31, 2007, 2006 and 2005:

Power

Guarantor Subsidiaries

Other Subsidiaries

Consolidating Adjustments

Total

(Millions)

For the Year Ended December 31, 2007:

Revenues

$

$

7,836

$

114

$

(1,154

)

$

6,796

Operating Expenses

4

6,152

114

(1,154

)

5,116

Operating Income.

(4

)

1,684

1,680

Equity Earnings (Losses) of Subsidiaries

930

(40

)

(890

)

Other Income

191

295

(247

)

239

Other Deductions

(1

)

(169

)

(170

)

Interest Expense

(197

)

(161

)

(49

)

248

(159

)

Income Taxes

22

(680

)

17

(641

)

Loss on Discontinued Operations, net of tax benefit

(8

)

(8

)

Net Income (Loss)

$

941

$

929

$

(40

)

$

(889

)

$

941

As of December 31, 2007:

Current Assets

$

2,553

$

3,632

$

360

$

(4,305

)

$

2,240

Property, Plant and Equipment, net.

149

3,669

934

(1

)

4,751

Investment in Subsidiaries.

3,538

168

(3,706

)

Noncurrent Assets

156

1,506

30

(255

)

1,437

Total Assets

$

6,396

$

8,975

$

1,324

$

(8,267

)

$

8,428

Current Liabilities.

$

99

$

4,556

$

1,057

$

(4,305

)

$

1,407

Noncurrent Liabilities

234

881

98

(255

)

958

Long-Term Debt

2,902

2,902

Member s Equity.

3,161

3,538

169

(3,707

)

3,161

Total Liabilities and Member s Equity

$

6,396

$

8,975

$

1,324

$

(8,267

)

$

8,428

For the Year Ended December 31, 2007:

Net Cash Provided By (Used In) Operating Activities

$

1,238

$

1,595

$

(584

)

$

(1,044

)

$

1,205

Net Cash (Used In) Provided By Investing Activities

$

(232

)

$

(596

)

$

(103

)

$

531

$

(400

)

Net Cash (Used In) Provided By Financing Activities.

$

(1,006

)

$

(1,001

)

$

687

$

513

$

(807

)

For the Year Ended December 31, 2006:

Revenues

$

$

7,030

$

139

$

(1,112

)

$

6,057

Operating Expenses

1

6,103

107

(1,114

)

5,097

Operating Income.

(1

)

927

32

2

960

Equity Earnings (Losses) of Subsidiaries

284

(252

)

(32

)

Other Income

171

199

6

(219

)

157

Other Deductions

(2

)

(88

)

(1

)

(91

)

Interest Expense

(188

)

(133

)

(44

)

217

(148

)

Income Taxes

12

(377

)

1

1

(363

)

Income (Loss) on Discontinued Operations, Including Loss on Disposal, net of tax benefit

8

(247

)

(239

)

Net Income (Loss)

$

276

$

284

$

(253

)

$

(31

)

$

276

As of December 31, 2006:

Current Assets

$

1,981

$

3,398

$

531

$

(3,440

)

$

2,470

Property, Plant and Equipment, net.

150

3,226

854

4,230

Investment in Subsidiaries.

4,287

201

(4,488

)

Noncurrent Assets

173

1,397

79

(221

)

1,428

Total Assets

$

6,591

$

8,222

$

1,464

$

(8,149

)

$

8,128

Current Liabilities.

$

97

$

3,160

$

1,251

$

(3,442

)

$

1,066

Noncurrent Liabilities

253

775

12

(219

)

821

Long-Term Debt

2,818

2,818

Member s Equity.

3,423

4,287

201

(4,488

)

3,423

Total Liabilities and Member s Equity

$

6,591

$

8,222

$

1,464

$

(8,149

)

$

8,128

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Power

Guarantor Subsidiaries

Other Subsidiaries

Consolidating Adjustments

Total

(Millions)

For the Year Ended December 31, 2006:

Net Cash Provided By (Used In) Operating Activities

$

1,105

$

1,076

$

14

$

(1,152

)

$

1,043

Net Cash (Used In) Provided By Investing Activities

$

(605

)

$

(1,016

)

$

25

$

1,206

$

(390

)

Net Cash Used In Financing Activities.

$

(500

)

$

(55

)

$

(39

)

$

(54

)

$

(648

)

For the Year Ended December 31, 2005:

Revenues

$

$

6,955

$

137

$

(1,065

)

$

6,027

Operating Expenses

6,288

95

(1,064

)

5,319

Operating Income.

667

42

(1

)

708

Equity Earnings (Losses) of Subsidiaries

218

(213

)

(5

)

Other Income

138

185

2

(138

)

187

Other Deductions

(42

)

(1

)

(43

)

Interest Expense

(142

)

(84

)

(14

)

140

(100

)

Income Taxes

(22

)

(288

)

(8

)

(318

)

Loss on Discontinued Operations, Including Loss on Disposal, net of tax benefit

7

(233

)

(226

)

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

(15

)

(1

)

(16

)

Net Income (Loss)

$

192

$

217

$

(213

)

$

(4

)

$

192

For the Year Ended December 31, 2005:

Net Cash (Used In) Provided By Operating Activities

$

(943

)

$

(371

)

$

1,050

$

400

$

136

Net Cash (Used In) Provided By Investing Activities

$

(157

)

$

133

$

37

$

(255

)

$

(242

)

Net Cash Provided By (Used In) Financing Activities

$

1,100

$

235

$

(1,087

)

$

(144

)

$

104

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

PSEG, Power and PSE&G

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

PSEG, Power and PSE&G

PSEG, Power and PSE&G have established and maintain disclosure controls and procedures to ensure that information required to be disclosed is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer and Chief Financial Officer of each company by others within those entities. PSEG, Power and PSE&G have established a disclosure committee which is made up of several key management employees and which reports directly to the Chief Financial Officer and Chief Executive Officer of each respective company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The Chief Financial Officer and Chief Executive Officer of each company have evaluated the effectiveness of the disclosure controls and procedures as of December 31, 2007 and, based on this evaluation, have concluded that the disclosure controls and procedures were effective in providing such reasonable assurance during the period covered in these annual reports.

Internal Controls

PSEG, Power and PSE&G

PSEG, Power and PSE&G have conducted assessments of their internal control over financial reporting as of December 31, 2007, as required by Section 404 of the Sarbanes-Oxley Act, using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as COSO . Management s reports on PSEG s, Power s and PSE&G s internal control over financial reporting is included on pages 177, 178 and 179, respectively. The Independent Registered Public Accounting Firm s report with respect to the effectiveness of PSEG s internal control over financial reporting is included on page 180. Management has concluded that internal control over financial reporting is effective as of December 31, 2007.

PSEG, Power and PSE&G continually review their respective disclosure controls and procedures and make changes, as necessary, to ensure the quality of their financial reporting. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, each registrant s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

PSEG, Power and PSE&G

None.

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING PSEG

Management of Public Service Enterprise Group (PSEG) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and implemented by the company s management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSEG s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSEG s assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSEG are being made only in accordance with authorizations of PSEG s management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSEG s assets that could have a material effect on the financial statements.

In connection with the preparation of PSEG s annual financial statements, management of PSEG has undertaken an assessment, which includes the design and operational effectiveness of PSEG s internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as COSO . The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSEG s internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSEG s financial reporting and the preparation of its financial statements as of December 31, 2007 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2007.

PSEG s external auditors, Deloitte & Touche LLP, have audited PSEG s financial statements for the year ended December 31, 2007 included in this annual report on Form 10-K and, as part of that audit, have issued a report on the effectiveness of PSEG s internal control over financial reporting, a copy of which is included in this annual report on Form 10-K.

/s/ RALPH IZZO

Chief Executive Officer

/s/ THOMAS M. O FLYNN

Chief Financial Officer

February 27, 2008

MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING Power

Management of PSEG Power LLC (Power) is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and implemented by the company s management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

Power s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of Power s assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of Power are being made only in accordance with authorizations of Power s management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of Power s assets that could have a material effect on the financial statements.

In connection with the preparation of Power s annual financial statements, management of Power has undertaken an assessment, which includes the design and operational effectiveness of Power s internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as COSO . The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that Power s internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of Power s financial reporting and the preparation of its financial statements as of December 31, 2007 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2007.

/s/ RALPH IZZO

Chief Executive Officer

/s/ THOMAS M. O FLYNN

Chief Financial Officer

February 27, 2008

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MANAGEMENT REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING PSE&G

Management of Public Service Electric and Gas Company is responsible for establishing and maintaining effective internal control over financial reporting and for the assessment of the effectiveness of internal control over financial reporting. As defined by the SEC in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and implemented by the company s management and other personnel, with oversight by the Audit Committee of the Board of Directors to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America (generally accepted accounting principles).

PSE&G s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of PSE&G s assets; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of PSE&G are being made only in accordance with authorizations of PSE&G s management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of PSE&G s assets that could have a material effect on the financial statements.

In connection with the preparation of PSE&G s annual financial statements, management of PSE&G has undertaken an assessment, which includes the design and operational effectiveness of PSE&G s internal control over financial reporting using the framework promulgated by the Committee of Sponsoring Organizations of the Treadway Commission, commonly referred to as COSO . The COSO framework is based upon five integrated components of control: control environment, risk assessment, control activities, information and communications and ongoing monitoring.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projection of any evaluation of effectiveness to future periods is subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Based on the assessment performed, management has concluded that PSE&G s internal control over financial reporting is effective and provides reasonable assurance regarding the reliability of PSE&G s financial reporting and the preparation of its financial statements as of December 31, 2007 in accordance with generally accepted accounting principles. Further, management has not identified any material weaknesses in internal control over financial reporting as of December 31, 2007.

/s/ RALPH IZZO

Chief Executive Officer

/s/ THOMAS M. O FLYNN

Chief Financial Officer

February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of
PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED:

We have audited the internal control over financial reporting of Public Service Enterprise Group Incorporated and subsidiaries (the Company) as of December 31, 2007, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company s internal control over financial reporting is a process designed by, or under the supervision of, the company s principal executive and principal financial officers, or persons performing similar functions, and effected by the company s board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule listed in the Index at Item 15 as of and for the year ended December 31, 2007 of the Company and our report dated February 27, 2008 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedules, and included explanatory paragraphs regarding the adoption of Financial Accounting Standards Board Interpretation No. 48, *Accounting for Uncertainty in Income Taxes an Interpretation of FASB Statement 109* and Statement of Financial Accounting Standards No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*.

DELOITTE & TOUCHE LLP
Parsippany, New Jersey
February 27, 2008

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Executive Officers

PSEG, Power and PSE&G

The Executive Officers of each of Public Service Enterprise Group (PSEG), PSEG Power LLC (Power) and Public Service Electric and Gas Company (PSE&G), respectively, are set forth below, as indicated for each individual.

Name	Age as of December 31, 2007	Office	Effective Date First Elected to Present Position
Ralph Izzo (1)(2)(3)			

50

Chairman of the Board, President and
Chief Executive Officer (PSEG)

April 2007 to present

Chairman of the Board and Chief
Executive Officer (Power)

April 2007 to present

Chairman of the Board and Chief
Executive Officer (PSE&G)

April 2007 to present

Chairman of the Board and Chief
Executive Officer (Energy Holdings)

April 2007 to present

Chairman of the Board and Chief
Executive Officer (Services)

April 2007 to present

President and Chief Operating
Officer (PSEG)

October 2006 to March 2007

President and Chief Operating
Officer (PSE&G)

October 2003 to October 2006

Vice President Utility Operations
(PSE&G)

June 2002 to October 2003

Thomas M. O Flynn (1)(2)(3)

47

Executive Vice President and Chief
Financial Officer (PSEG)

July 2001 to present

Executive Vice President and Chief
Financial Officer (Power)

February 2002 to present

Executive Vice President and Chief
Financial Officer (PSE&G)

January 2007 to present

President and Chief
Operating Officer (Energy Holdings)

February 2007 to present

Executive Vice President Finance
(Services)

June 2001 to present

Executive Vice President and Chief
Financial Officer (Energy Holdings)

August 2002 to present

William Levis (1)(2)

52

President and Chief Operating Officer
(Power)

June 2007 to present

President and Chief Nuclear Officer
(Nuclear)

January 2007 to present

Senior Vice President and Chief Nuclear Officer (Salem/Hope Creek)

January 2005 December 2006

Vice President Mid-Atlantic Operations of Exelon Nuclear (Exelon Corporation)

July 2003 to December 2004

Site Vice President Limerick Generating Station of Exelon Nuclear (Exelon Corporation)

February 2001 to July 2003

Ralph LaRossa (1)(3)

44

President and Chief Operating Officer
(PSE&G)

October 2006 to present

Vice President Electric Delivery
(PSE&G)

August 2003 to October 2006

Vice President Delivery Operations Support
(PSE&G)

January 2003 to August 2003

Director Distribution Operations
(PSE&G)

June 2001 to January 2003

Name

Age as of December 31, 2007

Office

Effective Date First Elected to Present Position

R. Edwin Selover (1)(2)(3)

62

Executive Vice President and General Counsel (PSEG)

December 2006 to present

Senior Vice President and
General Counsel (PSEG)

April 2002 to December 2006

Executive Vice President and
General Counsel (PSE&G)

December 2006 to present

Senior Vice President and
General Counsel (PSE&G)

January 1988 to December 2006

Executive Vice President and General Counsel
(Power)

December 2006 to present

Executive Vice President and
General Counsel (Services)

December 2006 to present

Senior Vice President and
General Counsel (Services)

November 1999 to December 2006

Derek M. DiRisio (1)(2)(3)

43

Vice President and Controller (PSEG)

January 2007 to present

Vice President and Controller (PSE&G)

January 2007 to present

Vice President and Controller (Power)

January 2007 to present

Vice President and Controller
(Energy Holdings)

January 2007 to present

Vice President and Controller
(Services)

January 2007 to present

Assistant Controller Enterprise
(Services)

July 2004 to January 2007

Vice President Planning and Analysis
(Energy Holdings)

March 2004 to July 2004

Vice President and Controller
(Energy Holdings)

June 1998 to March 2004

Elbert C. Simpson (1)

59

President and Chief Operating Officer
(Services)

January 2007 to present

Senior Vice President Information
Technology (Services)

May 2002 to January 2007

Kevin J. Quinn (2)

51

President (ER&T)

January 2007 to present

Vice President Corporate Planning
(Services)

April 2000 to January 2007

Richard Lopriore(2)

58

President (Fossil)

May 2007 to present

Vice President Boiling Water Reactor Operations of Exelon Nuclear (Exelon Corporation)

February 2004 to April 2007

Corporate Vice President Operations Support of Exelon Nuclear (Exelon Corporation)

July 2003 to February 2004

Site Vice President Byron Generating Station of Exelon Nuclear (Exelon Corporation)

February 2001 to July 2003

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(1)

Executive Officer of PSEG

(2)

Executive Officer of Power

(3)

Executive Officer of PSE&G

Directors

PSEG

The information required by Item 10 of Form 10-K with respect to (i) present directors of PSEG who are nominees for election as directors at PSEG s 2008 Annual Meeting of Stockholders, and directors whose terms will continue beyond the meeting, and (ii) compliance with Section 16(a) of the Securities Exchange Act of 1934, as amended, is set forth under the headings Election of Directors and Section 16(a) Beneficial Ownership Reporting Compliance in PSEG s definitive Proxy Statement for such Annual Meeting of Stockholders, which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange

Commission (SEC) on or about March 5, 2008 and which information set forth under said heading is incorporated herein by this reference thereto.

PSE&G

Caroline Dorsa has been a director since February 2003. Age 48. Has been Senior Vice President of Global Human Health, Strategy and Integration of Merck & Co., Inc. (Merck), Whitehouse Station, New Jersey, which discovers, develops, manufactures and markets human and animal health products, since February 2008. Was Senior Vice President and Chief Financial Officer of Gilead Sciences, Inc, from November 2007 to January 2008. Was Senior Vice President and Chief Financial Officer of Avaya, Inc., Basking Ridge, New Jersey, from February 2007 to November 2007. Was Vice President and Treasurer of Merck from December 1996 to January 2007.

Albert R. Gamper, Jr. has been a director of PSE&G since December 2000. Age 65. Director of PSEG. Until retirement, was Chairman of the Board of The CIT Group, Inc. of Livingston, New Jersey (a commercial finance company) from July 2004 until December 2004. Was Chairman of the Board and Chief Executive Officer of The CIT Group, Inc. from September 2003 to July 2004. Was Chairman of the Board, President and Chief Executive Officer of The CIT Group, Inc. from June 2002 to September 2003. Was President and Chief Executive Officer of The CIT Group, Inc. from February 2002 to June 2002. Was President and Chief Executive Officer of Tyco Capital Corporation from June 2001 to February 2002. Was Chairman of the Board, President and Chief Executive Officer of The CIT Group, Inc. from January 2000 to June 2001, and President and Chief Executive Officer of The CIT Group, Inc. from December 1989 to December 1999. Trustee to the Fidelity Group of Funds.

Conrad K. Harper has been a director of PSE&G since May 1997. Age 67. Director of PSEG. Of Counsel to the law firm of Simpson Thacher & Bartlett LLP, New York, New York since January 2003. Was a partner from October 1996 to December 2002 and from October 1974 to May 1993. Was Legal Adviser, United States Department of State from May 1993 to June 1996. Director of New York Life Insurance Company.

Ralph Izzo has been a director of PSE&G since October 2006. For additional information, see Executive Officers table above.

Power

Stephen C. Byrd has been a director of Power since February 2008. Age 34. Senior Vice President of Business Development, Strategy and M & A (Services). Was previously Executive Director of Morgan Stanley.

Ralph Izzo has been a director of Power since October 2006. For additional information, see Executive Officers table above.

William Levis has been a director of Power since April 2007. For additional information, see Executive Officers table above.

Richard P. Lopriore has been a director of Power since June 2007. For additional information, see Executive Officers table above.

Thomas M. O Flynn has been a director of Power since July 2001. For additional information, see Executive Officers table above.

Kevin J. Quinn has been a director of Power since April 2007. For additional information, see Executive Officers table above.

R. Edwin Selover has been a director of Power since June 1999. For additional information, see Executive Officers table above.

Elbert C. Simpson has been a director of Power since April 2007. For additional information, see Executive Officers table above.

PSEG, Power and PSE&G

Code of Ethics

Our Standards of Integrity (Standards) is a code of ethics applicable to us and our subsidiaries. The Standards are an integral part of our business conduct compliance program and embody our commitment to conduct operations in accordance with the highest legal and ethical standards. The Standards apply to all of our directors, employees (including PSEG s, Power s and PSE&G s principal executive officer, principal financial officer, principal accounting officer or Controller and persons performing similar functions) worldwide. Each such person is responsible for understanding and complying with the Standards. The Standards are posted on our website, www.pseg.com/investor/governance. We will send you a copy on request.

The Standards establish a set of common expectations for behavior to which each employee must adhere in dealings with investors, customers, fellow employees, competitors, vendors, government officials, the media and all others who may associate their words and actions with us. The Standards have been developed to provide reasonable assurance that, in conducting our business, employees behave ethically and in accordance with the law and do not take advantage of investors, regulators or customers through manipulation, abuse of confidential information or misrepresentation of material facts.

If we adopt any amendment (other than technical, administrative or non-substantive) to or a waiver from the Standards that applies to any director or principal executive officer, principal financial officer, principal accounting officer or Controller, or persons performing similar functions of PSEG, Power or PSE&G and that relates to any element enumerated by the SEC, we will post the amendment or waiver on our website, www.pseg.com/investor/governance.

ITEM 11. EXECUTIVE COMPENSATION

PSEG

The information required by Item 11 of Form 10-K is set forth under the heading Executive Compensation in PSEG s definitive Proxy Statement for the 2008 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the U.S. Securities and Exchange Commission (SEC) on or about March 5, 2008 and such information set forth under such heading is incorporated herein by this reference thereto.

Power

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

PSE&G

COMPENSATION COMMITTEE REPORT

The Organization and Compensation Committee of the Board of Directors has reviewed and discussed the Compensation Discussion and Analysis included in this Annual Report on Form 10-K with management and with Frederic W. Cook, Co., Inc., the Committee s independent compensation consultant. Based on such review and discussions, the Organization and Compensation Committee recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Report.

Shirley Ann Jackson, Chair
Albert R. Gamper, Jr.
William V. Hickey
Thomas A. Renyi
Richard J. Swift

February 19, 2008

COMPENSATION DISCUSSION AND ANALYSIS

Executive compensation is administered under the direction of the Organization and Compensation Committee (Committee) of PSEG, which oversees compensation programs and policies for PSEG and its subsidiaries. In light of responsibilities of the Committee, the Board of Directors of PSE&G does not believe it is necessary for it to have a separate committee of its own with respect to compensation matters. The Committee is made up of directors who are independent under NYSE rules and our requirements for independent directors.

The executive officers named in the Summary Compensation Table for PSE&G are: Mr. Izzo, the Chairman of the Board and CEO since April 1, 2007, who is also the Chairman, President and CEO of PSEG since April 1, 2007; Mr. Ferland, the former Chairman and CEO, who was also the Chairman, President and CEO of PSEG until March 31, 2007; Mr. O Flynn, the Executive Vice President and Chief Financial Officer of PSE&G and PSEG; Mr. Selover, the Executive Vice President and General Counsel of PSE&G and PSEG; Mr. LaRossa, the President of PSE&G; and Mr. DiRisio, the Vice President and Controller of PSE&G and PSEG. Under the compensation program administered by the Committee, each Named

Executive Officer (NEO) is compensated on the basis of all positions he or she holds with PSEG and its subsidiaries, including PSE&G.

Compensation Philosophy and Program

We have designed our Executive Compensation Program (Program) in a way that we believe will attract, motivate and retain the high-performing executives who are critical to our long-term success. We believe that we have structured the Program to link executive compensation to successful execution of our strategic business plans and meeting our financial, operational and other corporate targets. This design is intended to provide executives increased compensation when we do well as measured against our goals and to provide less compensation when we do not.

In setting compensation for a particular executive position, the Committee s philosophy is that the median of compensation of similar positions within an identified peer group of energy companies provides a reasonable starting reference point, which it then adjusts based on the performance and experience of the individual, the ability of the individual to contribute to the long-term success of the Company, and other factors, such as relative pay positioning among executives. The Committee believes that total direct compensation (salary, plus short-term incentive target, plus long-term incentive compensation target) is a better measure for evaluating executive compensation than focusing on each of the elements individually. The Committee does not set a formula to determine the various elements.

As designed, the Committee recognizes that actual delivered short-term and long-term incentive compensation is reflective of individual and corporate performance, so that the total direct compensation may differ from the targeted compensation for each individual in regard to each element of incentive compensation.

The Committee reviews the philosophy and objectives of the Program at least annually. The Committee s experience is that the evaluations described above must be considered and revised each year in setting compensation for executives. In assessing its continued appropriateness, the Committee examines our success and the contributions of the individual executives in achieving our business plans and annual goals. The Committee considers the motivational impact of the Program in attaining desired business results and our continued ability to attract and retain high-quality executives. Key factors in judging whether the Program has met its goals are the Program s relationship to our financial results, our future outlook and our ability to attract and retain key executive talent.

The Committee has the responsibility to review, approve and modify, as necessary, the Program and each of its constituent elements.

Compensation Consultant

The Committee has the authority to retain independent compensation consultants, with sole authority for their hiring and firing. Since October 2006, the Committee has retained Frederic W. Cook & Co., Inc. (Cook) as its executive compensation consultant to provide the Committee information and advice independently from management. Cook does not and will not perform any other services for us or our subsidiaries. Its only roles are advising the Committee on executive compensation, and the Corporate Governance Committee on matters pertaining to compensation of directors who are not executive officers. Responsibility for assignment to, and evaluation of work by Cook is solely that of the Committee and, beginning in April 2007 with respect to non-officer directors, the Corporate Governance Committee. In furtherance of Cook s independence, management receives copies of certain materials provided by Cook to the Committee only after the materials have been provided to the Committee. The scope of Cook s assignment is to provide general advice relating to all aspects of executive compensation, including the review of our current compensation programs and levels, benefit plans, provision of comparative industry trends and peer data and the recommendation of program and pay level changes.

The Committee has engaged Cook to perform reviews of our approach to and delivery of executive compensation. The scope of Cook s engagement includes annual reviews of the CEO s and other executive officers specific compensation levels, including analysis of peer group data and the mix of base salary, equity, incentive and other payments. The results of Cook s review were used in setting executive officers compensation for 2007. In setting executive base pay levels for 2008 and cash payments determined for 2007 performance under the Management Incentive Compensation Plan (MICP), Cook provided data as to executive compensation trends within the peer group and within general industry. Cook also provided specific compensation data from the peer group s 2007 proxy statements and reviewed more current peer group data provided by management s external consultant, Towers Perrin, to assist the Committee in establishing the CEO s compensation and to assist the Committee in reviewing the CEO s recommendations for the compensation of other executive officers.

We pay the fees of the compensation consultants retained by the Committee. In addition, we have agreed to indemnify Cook for certain matters related to Cook s engagement by the Committee, other than matters involving negligence or intentional misconduct by Cook. The Committee also utilizes the services of our internal compensation professionals.

Recent Committee Activities

In setting 2008 compensation for each executive officer, the Committee examined the following elements of compensation:

Base salary;

Total cash compensation, consisting of base salary plus annual incentive target levels and the performance criteria under the MICP to earn those payments; and

Total direct compensation, consisting of total cash compensation plus long-term incentive compensation grant levels and the performance criteria under the Long-Term Incentive Plan (LTIP) to earn those grants.

During several meetings in 2006 and 2007, the Committee considered recommendations from Cook and management with regard to compensation design and effectiveness. As a result, the Committee determined, in January 2007, to adopt a new peer group of companies as a beginning reference point for officer compensation. At the Committee s December 2007 meeting, the peer group was further modified. These changes are described below under Peer Group.

In addition, after reviewing competitive practices within the peer group and within a larger sample of the energy services industry, the Committee approved the following actions during 2007:

Long-term equity awards, including those granted in December 2007, now reflect provisions for prorated vesting upon retirement and for the forfeiture of unvested and unpaid grants and the return of any long-term award received within one year of termination of employment for breaches of non-compete, non-solicitation and confidentiality agreements;

Provisions were added to the MICP and LTIP for the repayment by the CEO, CFO and other participants of annual and long-term awards and any profits from the sale of PSEG securities in the year following a restatement of financial statements due to misconduct;

A policy for the leasing and use of charter aircraft was adopted; and

A Stock Ownership and Retention Policy for officers was adopted.

In addition, in connection with its responsibilities to review, discuss and make a recommendation to the Board in regard to the Compensation Discussion and Analysis included in the annual proxy statement, the Committee reviewed the Company s process for the reporting of executive compensation and preparation of the proxy statement. The Committee made several recommendations to management and reviewed and discussed management s responses to SEC comments received on the executive compensation disclosure in our 2007 Proxy Statement.

Compensation Policies

The Committee has established compensation policies to implement the compensation philosophy stated above. To meet our compensation objectives and to focus executive efforts on improving corporate performance, the Committee has developed and currently administers pay delivery systems that fall into three broad categories:

Base salary;

Annual cash incentive compensation, including annual performance-based incentives; and

Long-term incentive compensation, including awards such as restricted stock, restricted stock units, stock options and performance units.

Each of these components of compensation, including our related policies regarding determination and evaluation, is discussed further below. Our policy is to provide a mix of these components in the proportion best designed, as determined by the Committee, to achieve our compensation objectives. The Committee annually reviews with Cook the relationships among these components relative to the peer group, including cash, equity, performance-based pay, incentives, amount at risk and vesting schedules. The Committee does not have specific proportional factors it takes into account when establishing these components. The Committee s decisions in determining compensation for 2008 were made independent of prior equity awards, outstanding performance units, pensions or future compensation opportunities.

In addition to the above components of compensation, our practice has been to provide the following benefits (described more fully below) to non-represented employees generally, including the NEOs:

Post-employment benefits, including defined benefit pension plans, severance and change-in-control benefits;

Health care programs;

Employee Stock Purchase Plan (5% discount); and

A defined contribution plan (the Thrift Plan).

Depending upon the individual, NEOs and other key employees are provided with certain additional benefits, such as deferred compensation opportunities, enhanced post-employment benefits and a limited number of perquisites, in amounts deemed appropriate by the Committee and management based on the individual s position and ability to contribute to the achievement of our business goals.

We do not provide a tax gross-up of benefit amounts deemed to be taxable income under federal or state income tax laws and regulations, except for gross-ups:

contained in certain employment agreements with senior managers, described below;

of certain benefits resulting from a termination of employment following a change-in-control for certain executive officers covered under our Key Executive Severance Plan;

of relocation expenses under a program generally available to all employees; and upon individual determinations made by management on a case-by-case basis, primarily in the case of newly-hired executives.

Role of Chief Executive Officer

The CEO attends Committee meetings, other than executive sessions. Other executive officers and compensation professionals may attend portions of Committee meetings as requested by the Committee. The CEO recommends changes to the salaries of his direct reports (who include the NEOs) within an overall base salary budget approved by the Committee and the Committee considers these recommendations in the context of the peer group. The CEO recommends incentive compensation targets (expressed as a percentage of base salary for the MICP) and LTIP grants as well as the associated goals, objectives and performance evaluations. Management s data provided to the Committee generally includes a recommendation with respect to CEO compensation which, historically, has reflected the average base compensation adjustment and average MICP performance factor of other officers.

The design and effectiveness of compensation policies and programs are reviewed by the CEO periodically in light of general industry trends and the peer group and recommendations for changes are made to the Committee as deemed advisable by the CEO. The CEO reviews such compensation matters with our internal compensation professionals and other consultants. The Committee believes that the role played by the CEO in this process is reasonable and appropriate because the CEO is uniquely suited to evaluate the performance of his direct reports.

Peer Group

The Committee sets executive compensation so as to be competitive with other large energy companies within an identified peer group. The Committee looks at base salary, total cash compensation (base salary plus target annual incentive) and total direct compensation (base salary plus target annual incentive plus target long-term incentive) as the elements of compensation within the peer group for purposes of benchmarking. General industry data may sometimes be taken into consideration for certain positions where valid data for comparable positions may not be available within the peer group.

2007 Peer Group

In determining NEO compensation for 2007 (except for Mr. DiRisio), the following group of energy companies with reported net income averaging approximately $1 billion a year and market capitalization averaging about $16 billion was identified as the peer group. PSEG s net income and market capitalization are approximately at the median of this group.

American Electric Power Company, Inc.
Consolidated Edison, Inc.
Dominion Resources, Inc.
Duke Energy Corporation
Edison International
Entergy Corporation
Exelon Corporation
FirstEnergy Corp.
FPL Group, Inc.
PG&E Corporation
Progress Energy, Inc.
Sempra Energy
The AES Corporation
The Southern Company
The Williams Companies, Inc.
TXU Corp.
Xcel Energy Inc.

Due to the timing of the transition to the 2007 peer group, the peer group utilized for Mr. DiRisio for 2007 included, in addition to all those companies in the 2007 peer group: Ameren Corporation, CenterPoint Energy Inc, CMS Energy Corporation, Constellation Energy Group, Inc., DTE Energy Company, JEA, ONEOK, Inc., Pepco Holdings, Inc., PPL Corporation, Reliant Resources Inc., Tennessee Valley Authority and UPS Resources Corporation.

2008 Peer Group

In December 2007, management recommended and, after conferring with Cook, the Committee agreed to change the peer group of companies for 2008 executive compensation benchmarking. The Committee agreed to add Constellation Energy and PPL Corp. to the peer panel, since their size and operations are comparable to ours, and to remove AES Corp., TXU and Williams Companies (since AES has principally international operators, TXU is no longer a public company and Williams is principally a gas company). Beginning in 2008, this new peer group is being used as a reference point for competitive executive compensation and also as a major comparison factor in assessing our performance under our annual and long-term incentive plans. The revised peer group had reported net income averaging approximately $1.1 billion a year and market capitalization averaging $19.5 billion. Based on our net income, market capitalization and business focus, the Committee agrees that this group is more closely aligned with PSEG. The new peer group is:

American Electric Power Company, Inc.
Consolidated Edison, Inc.
Constellation Energy Group, Inc.
Dominion Resources, Inc.
Duke Energy Corporation
Edison International
Entergy Corporation
Exelon Corporation
FirstEnergy Corp.
FPL Group, Inc.
PG&E Corporation
PPL Corporation
Progress Energy, Inc.
Sempra Energy
The Southern Company

Xcel Energy Inc.

As an initial positioning, the Committee targets the median (50th percentile) for comparable positions to those of our officers within this peer group for total cash compensation, which is the total of base salary and annual cash incentive compensation. The mix of base salary and annual cash incentive for each of the executive positions is surveyed from this peer group. The reported pay structure from the competitive analysis is used as a general guideline in determining the appropriate mix of compensation among base salary, annual incentive opportunity and long-term compensation opportunity. There is no predetermined formula regarding the allocation of salary and incentives. The mix of incentives is selected to be reflective of the competitive practice found in this peer group for each of the pay components listed above and what the Committee determines to be the right mix of compensation within our officer group. As mentioned above, the Committee believes that the total direct compensation is a better approach for evaluating executive compensation than focusing on each of the elements individually.

Compensation Components

Base Salary

The Committee considers the median of the base salaries provided to executives in the peer group who have duties and responsibilities similar to those of our executive officers as the reference point for competitive base salaries. The Committee also considers the executive s current salary and makes adjustments based principally on individual performance and experience. The NEOs base salary levels are reviewed annually by the Committee using a budget it establishes for merit increases and salary survey data provided by Towers Perrin. Benchmark competitive base salary levels are determined and established for all the NEOs as well as for other officers. Annually, the individual performance of the executives with respect to individual and corporate performance criteria is determined and taken into account when setting salaries.

The Committee considers base salaries and base salary adjustments for individual NEOs, other than the CEO, based on the recommendations of the CEO, considering the individual s level of responsibilities, experience in position, sustained performance over time, results during the immediately preceding year and the executive s pay in relation to the benchmark median. Performance metrics included achievement of business plans, financial targets, safety and operational results, customer satisfaction, regulatory outcomes and other factors. In addition, factors such as leadership ability, managerial skills and other personal aptitudes and attributes are considered. Base salaries for satisfactory performance are targeted at the median (50th percentile) of the competitive benchmark data.

For 2007, the merit increase budget was set at 3.75% and base salaries for the NEOs as a group were increased by 3.6%. In 2007, until his retirement on March 31st, Mr. Ferland was paid a salary at an annualized rate of $1,160,000. On Mr. Izzo s election as President and COO in October 2006, Mr. Izzo s annual base salary rate was set at $700,000. Effective January 1, 2007, Mr. Izzo s annual rate of base salary as COO was increased to $725,000. On his election as Chairman of the Board and CEO, effective April 1, 2007, Mr. Izzo s base annual salary rate was set at $900,000.

For 2008, the merit increase budget was set at 3.75%. For 2008, NEO base salaries, as a group, increased 4.8% from 2007 levels to reflect general market adjustments for comparable positions. The 4.8% average included a special market-based pay adjustment that the Committee determined was needed to reduce the gap between current salary and the competitive pay level reported by the 2007 peer group and the 2008 peer group companies for Mr. LaRossa s position.

Effective January 1, 2008, the annual rate of base salary for Mr. Izzo was increased by 5.6% to $950,000, which is below the median of base salary provided to CEOs of the peer group companies. In determining base salary for the CEO, the Committee considered his tenure in position, his individual performance during 2007 in relation to corporate performance factors such as achievement of business plans, financial results, safety, human resources management, nuclear operations and civic leadership. The prime reason that Mr. Izzo s new salary is below the median of the peer group is his relatively recent promotion to the CEO position. The Committee determined the 2008 annual rates of base pay for the other NEOs as $426,000 for Mr. LaRossa, $618,000 for Mr. O Flynn, $520,000 for Mr. Selover and $273,000 for Mr. DiRisio.

Mr. Izzo s salary of $950,000 exceeds that of other NEOs due to the greater level of duties and responsibilities undertaken by the CEOs as the principal executive officers to whom NEOs typically report, and to whom the board of directors will look for the execution of corporate business plans.

Annual Cash Incentive Compensation

The MICP, which was approved by stockholders in 2004, is an annual cash incentive compensation program for officers. To support the performance-based objectives of our compensation program, corporate and business unit goals and measures are established each year based on factors deemed necessary to achieve our financial and non-financial business objectives. The goals and measures are established by the CEO for the NEOs reporting to him, and for all other officers by the individual to whom he or she reports. The goals and measures applicable to each NEO for 2007 are further discussed below.

The MICP sets a maximum award fund in any year of 2.5% of PSEG s net income. The formula for calculating the maximum award fund for any plan year was determined at the time of plan adoption by reference to, among other things, similar award funds in use by other companies and review of executive compensation plan practices that were designed to address compliance with the requirements of Internal Revenue Code Section (IRC) 162(m), which, as explained below, limits the Federal income tax deduction for compensation in excess of certain limits. The Committee annually reviews the adequacy of the award fund calculation relative to the Committee s determination of the appropriate level of annual cash incentive compensation for plan participants. If appropriate, the Committee will recommend for stockholder approval any changes to the MICP it deems required to align the plan s terms with the our compensation objectives.

The CEO s maximum award cannot exceed 10% of the award fund. The maximum award for each other participant cannot exceed 90% of the award fund divided by the number of participants, other than the CEO, for that year. For 2007 performance under the MICP, these limits were $33,375,425 for the total award pool (of which $10,638,200 was awarded), $3,337,543 for the CEO s maximum award and $566,753 for each other participant s maximum award.

Subject to the overall maximums stated above, NEOs are eligible for annual incentive compensation based on a combination of the achievement of individual performance goals by each officer which determines his/her Individual Performance Factor, as adjusted by overall corporate performance, as measured by the Corporate Factor. The Corporate Factor is a financial measure, Return on Equity (ROE), which is a relative performance assessment comparing our ROE against the median ROE of other companies. For 2007, ROE was measured against the performance of energy companies that comprise the Dow Jones Utility Index (DJUI). For 2008, this comparison will be to the 2008 Peer Group. This Corporate Factor is a significant determinant of MICP awards. A maximum award is based on a comparative performance factor of 1.5 and is achieved if our annual ROE, as measured on September 30, exceeds the median ROE performance of the group of energy companies that make up the DJUI. The minimum award threshold, based on a comparative performance factor of 0.5, is reached if our ROE is not more than five hundred basis points below the DJUI median. If the ROE is less than five hundred basis points below the DJUI median, the comparative performance factor is 0.

Actual incentive awards for participants in the MICP are computed as follows: (A) the participant s Target Award Amount (% of base salary) is multiplied by (B) the participant s Individual Performance Factor (0.0 to 1.5), which, in turn, is multiplied by (C) the Corporate Factor to arrive at the Final Award. In no case, however, may a Final Award exceed the lesser of (i) 1.5 times the participant s Target Award Amount or (ii) the maximum amount allowed for that participant under the total award pool for that year.

Performance goals and levels of achievement for NEOs are set forth below. Each NEO position has a targeted incentive award established by the Committee at the beginning of each year ranging from 60% to 100% of base salary. Annual incentive awards are intended to provide a competitive level of compensation if we meet our financial goals and the NEO achieves his or her business unit and individual goals. Since MICP targets are set as a percentage of base salary, increases in salary affect target bonuses. Incentive award targets are established for each NEO s position and reflect the median reported incentive target for similar positions within the peer panel.

For the 2007 performance year, based on PSEG s ROE of 19.0%, as compared with the median ROE of the companies comprising the DJUI of 14.5%, the Corporate Factor applied to MICP participants was 1.45. For reference, the following table shows the three- year comparison of the PSEG ROE with that of the DJUI median return on equity performance as follows:

MICP Corporate Factor ROE (%)	**PSEG**	**DJUI Median**	**Corporate Factor**
2007	19.0	14.5	1.45
2006	15.3		

13.4

1.19

2005

13.2

13.2

1.00

For 2007, Mr. Izzo s Individual Performance Factor was 1.162, the average of the Individual Performance Factors of all MICP participants. This individual factor was multiplied by the Corporate Factor of 1.45, producing a result in excess of 1.5. The Committee therefore reduced the award to 1.5, as required by the Committee s administrative regulations under the MICP. The MICP awards of the NEOs for 2007 are shown in the Summary Compensation Table. The Committee made its determinations regarding MICP awards for the 2007 performance year in February 2008 for payment in early March 2008. There were no instances in which the Committee awarded compensation absent achievement of relevant performance goals, or in which it waived or modified goals.

The following table sets forth the goals, measure and performance factors achieved for 2007, for each NEO other than Mr. Ferland. Mr. Ferland s compensation is separately discussed below, in light of his retirement in March 2007. Under the provisions of the MICP, the Individual Performance Factor achieved by each NEO was multiplied by the Corporate Factor, with the resulting amount subject to a maximum of 1.5 times his/her Target Award amount. The awards of each of the NEOs were limited by this maximum of 1.5. The maximum factor was reached because of the relative importance of the Corporate Factor in determining a participant s Final Award. For 2007, the Corporate Factor was 1.45 out of a maximum of 1.5, which reflects PSEG s strong operating performance and financial results for the year. As indicated above, the MICP is designed to reflect this strong performance in the awards granted to participants.

2007 MICP Goals and Performance

Name

Individual
Performance
Target Award1

Goals

Overall Performance Result2

Financial

Operational

Strategic

Individual
Factor

Total
Factor

Award
$

% of
Base
Salary

Target
$

Weight

Achievement Factor

Weight

Achievement Factor

Weight

Achievement Factor

Izzo3

95

%8

855,000

Not
Applicable

Not
Applicable

Not
Applicable

1.162

1.500

1,282,500

O Flynn4

60

%

360,000

30%

1.486

30%

1.148

40%

1.050

1.210

1.500

540,000

Selover5

60

%

303,000

20%

1.304

40%

1.195

40%

0.850

1.079

1.500

454,500

LaRossa6

60

%

228,000

40%

1.469

30%

0.872

30%

0.792

1.087

1.500

342,000

DiRisio7

45

%

114,750

30%

1.315

40%

0.993

30%

1.100

1.139

1.500

172,100

1

Percent of annual base salary.

2

Individual Performance Factors achieved may range from a minimum of 0.0 to a maximum of 1.5, with targeted performance at 1.0. Each NEO s Individual Performance Factor as shown above was multiplied by the Corporate Factor to determine the awards as shown in the table. Awards are capped at 1.5 times the target award amount.

3

Mr. Izzo s results reflect an average of all participant goal factors.

4

Mr. O Flynn s primary goals were:

Financial goals address earnings and cash flow targets for Energy Holdings (weighted @ 30%). The result was 1.486.

Operational goals cover improving credit profile, optimization of capital structure for PSEG Global and Energy Holdings, investor relations effectiveness, fossil operations benchmarking, accuracy of financial reports and the assessment of PSEG s capital project results(weighted @ 30%). The result was 1.148.

Strategic goals include corporate merger and acquisition and overall business strategy (weighted @ 10%), growth opportunity assessments (weighted @ 10%), Energy Master Plan execution (weighted @ 10%) and Energy Holding s strategic alternatives (weighted @ 10%). The results were 1.000, 1.500, 0.500 and 1.200, respectively.

Mr. Selover s primary goals were:

Financial goal addresses the financial planning and contribution of the Law function to Services (weighted @ 20%). The result on the measure was 1.304.

Operation goals include an end-of-year client assessment of services rendered by the various units that make up the Law organization (weighted @ 40%). The result of the measure was 1.195.

Strategic goal include plans to preserve investment in energy efficient and environmentally sound products and services as defined in PSEG s Energy Master Plan and to support PSEG s generation business with respect to the impact of programs that regulate greenhouse gases (weighted @ 40%). The result of the measure was 0.850.

Mr. LaRossa s primary goals were:

Financial goals address total capital expenditures against business plan and productivity improvements from prior year expenditures (weighted @ 10%) and overall earnings against target projections (weighted @ 30%). The results were 1.375 and 1.500, respectively.

Operational goals include employee safety measures (weighted @ 10%), customer service satisfaction measures (weighted @ 10%) and electric and gas reliability and safety measures (weighted @ 10%). Results for the safety, customer service and system reliability measures were 0.656, 1.063 and 0.896, respectively.

Strategic goals include the introduction of a management business model across PSE&G (weighted @ 5%), the implementation of a new customer service and billing system (weighted @ 10%) and a strategy to preserve investment in energy efficient and environmentally sound products and services-Energy Master Plan (weighted @ 15%). The result for the management model introduction was 1.250, for the customer system implementation was 1.000 and for the Energy Master Plan was 0.500.

7

Mr. DiRisio s primary goals were:

Financial goals address meeting the accounting departmental budget (weighted @ 15%) and managing audit fees to be more reflective of industry standards (weighted @ 15%). The results on the measures were 1.130 and 1.500, respectively.

Operational goals include timeliness and quality of results and controls in connection with Sarbanes Oxley Act section 404 compliance (weighted @ 16%) and accuracy of accounting records, final adjustments and quality of accounting estimates (weighted @ 24%). The results were 1.225 and 0.838, respectively.

Strategic goals include staffing of the accounting department to reduce use of part-time contracted associates (weighted @ 18%) and implementation of a process to ensure accurate reporting of fixed asset accounting and depreciation expense (weighted @ 12%). The results were 1.000 and 1.250, respectively.

8

Composite based on 80% for three months and 100% for nine months, reflecting Mr. Izzo s election as CEO of PSEG on April 1, 2007.

For the 2008 MICP plan year, the Committee has determined to modify the approach to the CEO s proposed plan award by establishing a set of individual goals for Mr. Izzo. The Committee believes that determining MICP compensation for the CEO on the basis of individual goal results multiplied by the Corporate Factor, rather than on the basis of the average of the individual performance factors of all officers, will better align the CEO s individual compensation scheme to that applicable to all officers and will focus the CEO s efforts on agreed objectives that are important to the Company s success. The Committee has established an individual performance Target Award of 100% of base pay and has established the following 2008 individual goals for Mr. Izzo, which the Committee intends to weight approximately equally:

Financial performance, including earnings, quality of earnings, credit ratings, access to capital, adequacy of internal controls and compliance, and continuous improvement in operational performance to produce strong financial results;

Strategic development, including deployment of capital through disciplined investment decisions, optimizing total shareholder return and quality of consultations with the Board;

Leadership and management development, including succession planning, the recruitment, development and retention of a diverse, talented workforce and support in the recruitment of Board members; and

Thought leadership, including the prominence of PSEG in the public discourse on issues of vital importance to stockholders, employees, customers and policymakers.

The Committee believes that the 2008 goals established for the other NEOs are consistent in nature with their 2007 goals and accordingly are not necessary to an understanding of the NEOs 2007 goals and performance. These 2008 goals will be described in the 2009 proxy statement. The NEOs 2006 goals and performance were significantly related to the proposed merger with Exelon Corporation, which was cancelled in September 2006. The Committee believes that such goals and performance likewise are not relevant to an understanding of the NEOs 2007 goals and performance.

Long-Term Incentive Compensation

The LTIP was approved by stockholders at the 2004 Annual Meeting. To permit flexibility, the LTIP provides for different forms of equity awards including:

stock options (the right to purchase shares of Common Stock at a stated price);

restricted stock (shares of Common Stock subject to forfeiture if certain service requirements or other restrictions are not met); during the restriction period, recipients of shares of restricted stock may exercise full voting rights with respect to those shares and are entitled to receive all dividends on the shares;

restricted stock units (the right to receive shares of Common Stock in the future which is subject to transfer restrictions and a risk of forfeiture or other restrictions that will lapse upon the completion of service by the recipient, or achievement of other objectives); and

performance units (the right to receive a stated number of shares of Common Stock upon the attainment of certain performance goals).

NEOs, other officers as determined by the Committee and other key employees, as selected by the CEO within guidelines established by the Committee, are eligible to participate in the LTIP. This plan is designed to attract and retain qualified personnel for positions of substantial responsibility, to motivate participants toward goal achievement by means of appropriate incentives, to achieve long- range corporate goals, to provide incentive compensation opportunities that are competitive with those of other similar companies and to align participants interests with those of our stockholders.

The exercise price of any stock option granted under the LTIP may not be below the closing price of our Common Stock on the date of grant, no repricing may be done without stockholder approval and no discounted options may be granted. Performance goals are used for any performance-based awards.

For grants made in January 2007, the Committee determined that senior officers, including the NEOs (other than Mr. DiRisio), would be granted a long-term award consisting of 50% performance shares and 50% non-qualified stock options. For other participants, including Mr. DiRisio, 2007 awards consisted of 50% performance shares and 50% restricted stock. The Committee structured the grants in this manner to increase the performance-related nature of the grants to senior officers. The same weighting and form of long-term award grants was used for 2008 compensation awards made in December 2007, except that for Mr. DiRisio, restricted stock units were awarded instead of restricted stock.

Grant levels are determined by the Committee based upon several factors including the value of long-term incentive awards made by firms in the peer group to executives in similar positions and whose cash compensation is similar to each NEO as well as the individual s ability to contribute to our overall success. The level of grants is reviewed annually by the Committee. In general, when making LTIP grants, the Committee s determinations are made independently from any consideration of the individual s prior LTIP awards.

The CEO determines his recommendations for the size of LTIP grants for NEOs and each other participant in part by analyzing long-term incentive award values granted to executives for comparable positions as reported in the peer group. Median long-term incentive values for comparable levels of base salary for executive positions within the peer group are used as a further reference for determining the recommended grant size for NEOs and other officers. In making his recommendation for the size of a particular LTIP grant for each NEO, the CEO adjusts this average to reflect the individual s performance and ability to contribute to the long-term value of the Company.

In January 2007, the Committee granted stock options and performance shares to Mr. Izzo, Mr. Ferland and the other NEOs, as a component of 2007 compensation. Additional grants of performance units and stock options were made in March 2007 to Mr. Izzo upon his election to his current position. In December 2007, grants of stock options and performance units were made to Mr. Izzo and the other NEOs except Mr. DiRisio, who received performance units and restricted stock units, as a component of 2008 compensation.

Stock Options have a term of ten years and exercise prices based on the closing price on the date of grant. They vest one-third annually except for the December 2007 grant, which vests one-fourth annually. The performance units are subject to the achievement of certain performance goals related to PSEG s performance with respect to Total Shareholder Return (TSR) and ROE relative to the companies in the DJUI for a performance period ending on December 31, 2009 for the performance units granted in January and March and in the 2008 peer group for a performance period ending on December 31, 2010 for the performance units granted in December.

Target Total Direct Compensation

The Committee reviews base salary, target total cash compensation (base salary plus target annual cash incentive) and target total direct compensation (base salary plus target annual cash incentive plus long-term incentive) of each of the NEOs in comparison to the identified peer group. The data used for the 2007 and 2008 comparisons below are from the most recent data available for the companies in the 2007 peer group as of the time each comparison was made, provided to the Committee by management and Towers Perrin. The Committee considers a range of 90% to 110% of the 50th percentile of comparable positions to be within the competitive median.

2007

For 2007, base salary, target total cash compensation and target total direct compensation of the NEOs as a percentage of the comparative benchmark levels of the 2007 peer group are as follows:

Name

Izzo
%

O Flynn
%

Selover
%

LaRossa
%

DiRisio
%

Base Salary

83

97

102

86

91

Total Cash Compensation

83

93

102

84

91

Total Direct Compensation

84

96

95

93

87

The comparisons for Mr. Izzo reflect his compensation as of April 2007, when he became CEO.

2008

For 2008, base salary, target total cash compensation and target total direct compensation of the NEOs as a percentage of the comparative benchmark levels of the 2007 peer group are as follows:

Name

Izzo
%

O Flynn
%

Selover
%

LaRossa
%

DiRisio
%

Base Salary

77

106

111

87

95

Total Cash Compensation

77

105

111

87

97

Total Direct Compensation

81

94

97

91

98

For 2007 and 2008, Mr. Izzo s total direct compensation is below the median range primarily as a result of his recent promotion to the CEO position. The Committee set Mr. Izzo s 2008 LTIP award at 82% of the corresponding 2008 peer group level, which was designed to move him closer to the target total direct compensation range. The Committee expects his relative position, compared to the 2008 peer group, to change as he gains experience as CEO.

Compensation of E. James Ferland

Mr. Ferland retired as CEO effective March 31, 2007. In January 2007, the Committee increased Mr. Ferland s base salary by 3.6%. His target MICP, set at 100% of base salary, was $1,160,000. The Committee awarded Mr. Ferland an LTIP award of 88,000 stock options which vested upon his retirement, and 15,600 performance shares which are payable within 75 days of January 1, 2008. These LTIP awards were made in recognition of Mr. Ferland s substantial contributions to the Company over his long tenure as CEO, and were consistent with the provisions of his employment agreement.

For 2007, Mr. Ferland s base salary, target total cash compensation and target total direct compensation were 107%, 107% and 103%, respectively, compared to the 2007 peer group.

Other Executive Compensation Programs

Retirement

We provide certain retirement benefits to maintain practices that are competitive with companies in the energy services industry with which we compete for executive talent. In addition to the qualified pension plan, we maintain supplemental plans to provide competitive retirement benefits. These benefits are described below under Pension Benefits and were reviewed in November 2007 by the Committee, with the assistance of Cook.

Severance and Change-in-Control Benefits

We provide for severance benefits in the event of certain employment terminations. These benefits are available to officers, including the NEOs, in order to be competitive with the companies in the energy industry with which we compete for executive talent. The Committee, with the assistance of Cook, compares the benefits made available to NEOs and officers in the event of a termination or change-in-control to that generally offered by other companies in our industry. The multiples of components of compensation chosen as severance or change-in-control payments are based upon the comparative analysis.

We also provide severance benefits upon a change-in-control to officers, including the NEOs, and to certain key executive level employees. A change-in-control is by its nature disruptive to an organization and to many executives.

Such executives are frequently key players in the success of organizational change. To assure the continuing performance of such executives in the face of a possible termination of employment in the event of a change-in-control, we deem it prudent to provide a competitive severance package. In addition, some executives, not a key party to such transaction, may have their employment terminated following its completion. A severance plan with benefits applicable upon a change-in-control is an important element for attracting and retaining key executives.

Severance and change-in-control benefits are described below under Potential Payments Upon Termination of Employment or Change-in-Control. As noted there, the employment agreements of Messrs. Izzo and O Flynn also provide for certain severance benefits. The Committee, with the assistance of Cook, reviewed severance benefits in November 2007, comparing them with the benefits offered by the 2007 peer group. This review found that, while the severance benefits following a change-in-control are appropriately competitive, the benefits provided following involuntary severance for other reasons may not be competitive.

Perquisites

We provide certain perquisites that we believe are reasonably within compensation practices and are competitive with companies in the energy industry with which we compete for executive talent. These include automobile use, financial planning services, annual physical examinations, spousal travel to accompany executive officers on business trips (which requires the approval of the CEO), Company-purchased tickets to entertainment and sporting events, home security, home computer services and chartered air travel. These perquisites are described in the Summary Compensation Table.

Stock Ownership and Retention Policy

To strengthen the alignment of the interests of management with the interests of stockholders, we have established a Stock Ownership and Retention Policy (Policy), effective November 20, 2007.

Each officer is to maintain ownership of PSEG Common Stock having a market value in the following multiples of such officer s annual base salary, as in effect from time to time:

Position	**Multiple**
Chief Executive Officer	5

President/Chief Operating Officer	3
Executive Vice President	3
Senior Vice President	2
Vice President	1

Determination of whether an officer has met the requirement is made by multiplying the number of shares owned by the officer by the average share price for the 12 months preceding the officer s election, promotion or change in base salary.

In fulfilling the ownership requirement, all shares owned by the officer are counted, including (i) shares held in trusts for the benefit of immediate family members where the officer is the trustee, (ii) shares granted to the officer in the form of restricted stock and restricted stock units whether or not vested, and (iii) shares held by the officer in the Thrift Plan. Stock options and performance units (as distinct from shares which are actually issued as a result of exercise or vesting) are not counted. Shares subject to hedging or monetization transactions (such as zero-cost collars and forward sale contracts) that have the effect of allowing the officer to retain legal ownership without the full risks and rewards of that ownership, are not counted for purposes of either the ownership or retention provisions of the Policy.

Each officer serving as of the date the Policy was adopted must acquire the applicable amount of shares required by the Policy by the fifth anniversary of the date of adoption. Each newly elected or promoted officer must acquire the applicable amount of shares by the fifth anniversary of the date of election or promotion.

Each officer must retain not less than 100%, after tax and costs of issuance, of all shares acquired by the officer through equity grants including the vesting of restricted stock or restricted stock unit grants, the payout of performance awards and the exercise of option grants, until the officer s ownership requirement is met. Once the required ownership level is met, a covered officer must retain 25%, after tax and costs of issuance, of shares so acquired until the officer retires or his or her employment otherwise ends. The retention requirement does not apply to grants made before the Policy was adopted.

The Committee has the authority to vary the application of the provisions of the policy for good cause or exceptional circumstances. In the event an officer is not in compliance with any provision of this policy, the Committee may take such action as it deems appropriate, consistent with the provisions of our compensation plans and applicable law and regulations, to enable the officer to achieve compliance at the earliest practicable time or otherwise enforce this policy. Such action may include establishing conditions with respect to all or part of any MICP or LTIP award.

In making 2008 grants under the LTIP, the Policy was not a factor considered by the Committee.

The following table shows, for each NEO, the dollar amount of stock ownership required by the policy and the dollar amount of actual holdings as of February 15, 2008 (see Security Ownership of Directors, Management and Certain Beneficial Owners). For each of the NEOs, compliance must be achieved by November 20, 2012.

Name	**Required Amount1**	**Amount Held2**
Izzo	$ 4,750,000	$ 6,074,453

O Flynn

$

1,854,000

$

5,562,923

Selover

$

1,560,000

$

1,980,212

LaRossa

$

1,278,000

$

333,814

DiRisio

$

273,000

$

546,701

1

Determined on basis of base salary on January 1, 2008, the effective date of the current salary of each of the NEOs.

2

Based on average price of Common Stock for the twelve months preceding January 1, 2008

Accounting and Tax Implications

The Committee has considered the effect of the adoption of SFAS 123R (see Note 17. Stock Based Compensation) regarding the expensing of stock options in determining the nature of the grants under the LTIP. During 2007 the Committee, with the assistance of its independent compensation consultant, reviewed the competitiveness of the NEOs LTIP grants, as measured against the peer group, using reported SFAS 123R grant values and approved grants to the NEOs accordingly as reported above in Long-Term Incentive Compensation.

The Committee considers the tax-deductibility of our compensation payments. IRC Section 162(m) generally denies a deduction for United States federal income tax purposes for compensation in excess of $1 million for persons named in the proxy statement, except for compensation pursuant to stockholder-approved performance-based plans. Stockholder approval of the LTIP and MICP was received at the 2004 Annual Meeting of Stockholders. As a result, performance-based compensation under these plans is not now subject to the limitation on deductions contained in Section 162(m) of the IRC.

In 2007, Mr. Izzo and Mr. O Flynn had compensation (consisting of base salary and the taxable value of restricted stock that vested during the year) in excess of the amount deductible under Section 162(m) of the IRC. The Committee will continue to evaluate executive compensation in light of Section 162(m) of the IRC. During 2007, the Committee made all awards to the NEOs under the LTIP performance-based, except for restricted stock and restricted stock units.

In light of Section 162(m), as well as certain NYSE rules, the Committee s general policy is to present all incentive compensation plans in which executive officers participate to stockholders for approval prior to implementation.

SUMMARY COMPENSATION TABLE

Name and
Principal Position1

Year

Salary
($)2

Bonus
($)3

Stock
Awards
($)4

Option
Awards
($)5

Non-Equity
Incentive
Plan
Compensation
($)6

Change in
Pension
Value and
Non-Qualified
Deferred
Compensation
Earnings
($)7

All Other
Compensation
($)8,9

Total
($)

Ralph Izzo

2007

845,388

100,000

1,364,142

671,758

1,282,500

663,930

152,213

5,079,931

Chairman of the

2006

559,920

0

778,585

272,836

437,600

620,394

49,038

2,718,373

Board, Chief Executive Officer, President and Chief Operating Officer

E. James Ferland

2007

331,833

0

1,801,918

580,800

420,000

239,158

306,758

3,680,467

Chairman of the

2006

1,115,816

0

5,166,867

109,350

1,680,000

821,233

279,035

9,172,301

Board and Chief Executive Officer

Thomas M. O Flynn

2007

596,034

50,000

681,041

153,826

540,000

170,363

70,549

2,261,813

Executive Vice

2006

552,926

0

650,435

26,730

437,600

575,436

42,796

2,285,923

President and Chief Financial Officer

R. Edwin Selover

2007

501,963

0

696,875

366,816

454,500

54,787

41,717

2,116,658

Executive Vice

2006

473,225

0

425,019

17,819

356,300

494,725

46,989

1,814,077

President and General Counsel

Ralph LaRossa

2007

377,431

0

251,879

97,944

342,000

195,000

54,653

1,318,907

President and Chief

2006

238,720

0

155,230

4,536

176,400

135,000

38,826

748,712

Operating Officer (PSE&G)

Derek DiRisio

2007

252,208

0

135,095

0

172,100

45,000

20,350

624,753

Vice President

2006

214,196

58,800

97,893

4,536

112,900

101,000

20,353

609,678

and Controller

1

Mr. Izzo was elected to his current position effective April 1, 2007. He was President and COO of PSEG from October 1, 2006 until March 31, 2007 and President and COO of PSE&G through September 30, 2006.

Mr. Ferland retired on March 31, 2007.

Mr. LaRossa was elected to his current position effective October 1, 2006. Previously, he was Vice President Electric Delivery.

Mr. DiRisio was elected to his current position effective January 3, 2007. Previously he was Assistant Controller.

2

Mr. Ferland s 2006 salary includes $780,000 deferred under the Deferred Compensation Plan. Mr. Selover s 2007 salary includes $52,000 and his 2006 salary includes $39,000 deferred under the Deferred Compensation Plan.

3

In 2007, Mr. Izzo and Mr. O Flynn each received a special achievement award for smooth transition of the merger termination with Exelon and strong operating performance.

In 2006, Mr. DiRisio received a bonus representing a key employee retention award.

4

The amount shown reflects the expense included on PSEG s financial statements for 2007 and 2006 related to restricted stock awards, performance units and restricted stock units granted in current or prior years under the LTIP and still outstanding as determined under SFAS 123R. The fair value at the grant date of the number of shares of equity awards granted in 2007 is shown below in the Grants of Plan-Based Awards Table. Generally, restricted stock and restricted stock unit awards vest one-fourth annually. Awards made prior to 2007 vest one-third annually. Recipients receive dividends at the regular dividend rate and are paid on each regular dividend date. Under their terms, all shares of restricted stock vest upon retirement.

The amount shown for Mr. Ferland reflects the vesting of all his restricted stock and performance units upon retirement.

Performance units are denominated in shares of Common Stock and are subject to achievement of certain performance goals over a three-year period and are payable as determined by the Company in shares of stock or cash. For a discussion of the assumptions made in valuation, see Note 17. Stock Based Compensation.

Under SFAS 123R, the respective amounts attributable to restricted stock and performance units are as follows:

Izzo

Ferland

O Flynn

Selover

LaRossa

DiRisio

Restricted Stock (2007)

$

612,747

$

1,031,278

$

484,598

$

325,517

$

128,093

$

94,730

a

Performance Units (2007)

$

751,395

$

770,640

$

196,443

$

371,358

$

123,786

$

40,365

Restricted Stock (2006)

$

691,123

$

4,813,839

$

562,973

$

372,541

$

140,918

$

83,581

Performance Units (2006)

$

87,462

$

353,028

$

87,462

$

52,478

$

14,312

$

14,312

---

a

Includes restricted stock and restricted stock units, which are valued equally.

5

The amounts shown reflect the expense included on PSEG s financial statements for 2007 and 2006 related to options granted in current or prior years under the LTIP and still outstanding as determined under SFAS 123R. The fair value at the grant date of the number of shares of equity awards granted in 2007 is shown below in the Grants of Plan-Based Awards Table. For a discussion of the assumptions made in valuation see Note 17 to the Consolidated Financial Statements included in PSEG s 2007 Annual Report on Form 10-K.

6

Amounts awarded were earned under the MICP and determined and paid in the following year. Mr. Izzo and Mr. Ferland have elected to defer their entire 2007 awards under the Deferred Compensation Plan.

The entire 2006 awards were deferred under the Deferred Compensation Plan by Messrs. Izzo, Ferland and O Flynn.

7

Includes change in actuarial present value of accumulated benefit under defined benefit pension plans and supplemental executive retirement plans between December 31, 2006 and December 31, 2007 and between December 31, 2005 and December 31, 2006 determined by calculating the benefit under the applicable plan benefit formula for each of the plans, based on credited service and earnings in effect at the respective measurement dates. These changes are:

Izzo

Ferland

O Flynn

Selover

LaRossa

DiRisio

2007

$

626,000

$

0

$

157,000

$

15,000

$

195,000

$

45,000

2006

$

601,000

$

708,000

$

571,000

$

469,000

$

135,000

$

101,000

Includes interest earned under the Deferred Compensation Plan at Prime plus 1/2%, to the extent that it exceeds 120% of the applicable long-term rate. These amounts are:

Izzo

Ferland

O Flynn

Selover

LaRossa

DiRisio

2007

$

37,930

$

239,158

$

13,363

$

39,787

$

0

$

0

2006

$

19,394

$

113,233

$

4,436

$

25,725

$

0

$

0

8

Depending on the individual, includes perquisites and personal benefits which include (a) automobile, gas, parking and maintenance, (b) financial planning services, (c) physical examinations and related transportation, (d) home computer and related services, (e) home security systems, (f) airline clubs, (g) travel on chartered aircraft, (h) spousal travel and (i) personal/family entertainment. For automobiles, the lease value of the vehicle was used; for parking, the amount charged back to the NEO s business unit for the space was used; for the driver, actual compensation and benefit expense was used; for gasoline and maintenance, estimates were used based on the vehicle s annual mileage. For personal use of chartered aircraft, the actual cost charged to the NEO s business unit was used. For each NEO, the amount that exceeded the greater of $25,000 or 10% of his total perquisite and personal benefit amount is shown in the following chart:

Izzo

Ferland

O Flynn

Selover

LaRossa

DiRisio

Automobile, Gas & Parkinga

2007

$

135,973

$

43,828

$

27,407

$

25,462

$

28,263

$

12,099

a

Mr. Izzo and Mr. Ferland (until his retirement on March 31, 2007) received the services of a driver for business, commuting and occasional personal use.

In addition, we chartered aircraft to transport Mr. Ferland on some occasions when business needs precluded him from taking commercial flights, which had been scheduled for personal reasons. The cost of such charters was $25,830.

9

Includes $133,346 with respect to accrued vacation paid to Mr. Ferland at his retirement in 2007.

Includes compensation related to rabbi trust of $85,443 and $20,452 to Mr. Ferland and Mr. O Flynn, respectively in 2007.

Includes the following employer contributions to Thrift and Tax-Deferred Savings Plan:

Izzo

Ferland

O Flynn

Selover

LaRossa

DiRisio

2007

$

9,002

$

6,751

$

9,003

$

9,006

$

9,002

$

7,876

2006

$

8,803

$

6,600

$

8,803

$

8,806

$

8,804

$

7,704

GRANTS OF PLAN-BASED AWARDS TABLE*

Name

Grant Date1

Estimated Possible Payouts Under Non-Equity Incentive Plan Awards2

Estimated Future Payouts Under Equity Incentive Plan Awards3

All Other Stock Awards: Number of Shares of Stock or Units (#)

All Other Option Awards: Number of Securities Underlying Options (#)

Exercise or Base Price of Option Awards ($/Sh)

Grant Date Fair Value of Stock and Option Awards($)4

Threshold ($)

Target ($)

Maximum ($)

Threshold (#)

Target (#)

Maximum (#)

Ralph Izzo

N/A

427,500

855,000

1,282,500

0

0

Performance Units

01/16/07

0

24,600

49,200

992,979

Stock Options

01/16/07

140,000

32.93

1,019,200

Performance Units

03/20/07

0

23,000

46,000

1,261,205

Stock Options

03/20/07

113,000

39.17

1,023,780

Performance Units

12/18/07

0

52,800

105,600

2,788,104

Stock Options

12/18/07

199,800

48.21

2,289,708

E. James Ferland

N/A

580,000

1,160,000

1,740,000

0

0

Performance Units

01/16/07

0

15,600

31,200

770,640

Stock Options

01/16/07

88,000

32.93

580,800

Thomas M. O Flynn

N/A

180,000

360,000

540,000

0

0

Performance Units

01/16/07

0

14,600

29,200

589,329

Stock Options

01/16/07

82,000

32.93

596,960

Performance Units

12/18/07

0

11,000

22,000

580,855

Stock Options

12/18/07

45,800

48.21

524,868

R. Edwin Selover

N/A

151,500

303,000

454,500

0

0

Performance Units

01/16/07

0

9,200

18,400

371,358

Stock Options

01/16/07

52,000

32.93

353,600

Performance Units

12/18/07

0

7,800

15,600

411,879

Stock Options

12/18/07

33,000

48.21

378,180

Ralph LaRossa

N/A

114,000

228,000

342,000

0

0

Performance Units

01/16/07

0

9,200

18,400

371,358

Stock Options

01/16/07

52,000

32.93

378,560

Performance Units

12/18/07

0

7,800

15,600

411,879

Stock Options

12/18/07

33,000

48.21

378,180

Derek DiRisio

N/A

57,375

114,750

172,125

0

0

Performance Units

01/16/07

0

3,000

6,000

121,095

Restricted Stock

01/16/07

2,800

92,190

Performance Units

12/18/07

0

2,300

4,600

121,452

Restricted Stock Units

12/18/07

2,200

106,051

*

Reflects 2-for-1 split of PSEG Common Stock effective February 4, 2008

1

Relates to equity awards.

2

Represents possible payouts under MICP for 2007 performance. The actual awards were determined in February 2008; will be paid in March 2008 and are reported in the Summary Compensation Table.

Amounts for Mr. Izzo are pro-rated 9 months at 100% target and 3 months at 80% target.

Amounts for Mr. Ferland are prorated 3/12th, as he retired on March 31, 2007.

3

Represents LTIP awards described below.

4

Represents the fair value at the grant date of the equity awards granted in 2007. For a discussion of the assumptions made in valuation see Note 17. Stock Based Compensation.

Material Factors Concerning Awards Shown in Summary Compensation Table, Grants of Plan-Based Awards Table and Employment Agreements

Stock Split

The Board of Directors approved a 2-for-1 split for PSEG s common stock effective February 4, 2008. All share amounts and related exercise prices included in this proxy statement, retroactively reflect the effect of the stock split.

MICP

The Plan-Based awards for annual incentive compensation included in the Summary Compensation Table were paid in 2008 with respect to 2007 performance under the terms of the MICP. The range of possible awards for each NEO in relation to his Target Award is set forth in the Grants of Plan-Based Awards Table above. An explanation of the MICP and each NEO s individual performance goals, measures and performance factors achieved are described above under 2007 MICP Goals and Performance in Compensation Discussion and Analysis.

The NEOs MICP awards for 2007 were as follows:

Izzo

Ferland

O Flynn

Selover

LaRossa

DiRisio

$1,282,500

$420,000

$540,000

$454,500

$342,000

$172,100

LTIP

As discussed in the Compensation Discussion and Analysis and on the table shown above, LTIP awards were made to NEOs in 2007. The Committee, on January 16, 2007, approved the regularly scheduled grants in the form of stock options and performance shares to Mr. Izzo and the other named NEOs. In addition, Mr. Ferland received a grant of 88,000 stock options that vested on March 31, 2007, his retirement date and 15,600 performance shares which are payable within 75 days of January 1, 2008, subject to achievement of performance results. The January 16, 2007, grants for the other NEOs are shown in the above table with a performance measurement period for performance shares ending on December 31, 2009. The Committee approved, on March 20, 2007, a grant of 113,000 stock options to Mr. Izzo upon his election to the position of Chairman of the Board and CEO effective April 1, 2007. The Committee approved, on December 18, 2007, additional grants to the NEOs of stock options and performance shares. One-fourth of the options vest each December over a four-year period. A three-year performance period for performance shares ends December 31, 2010.

Grants of performance shares made on January 16, 2007 and June 19, 2007, allow award recipients to receive 100% of their grant amount if, for the three-year performance period ending on December 31, 2009, (a) PSEG s TSR placed it within the third quintile of the companies within the DJUI and (b) PSEG s ROE was within one percent (1%) of the ROE of the DJUI. For performance above or below these levels, the final award could be increased to as much as 200% of the grant amount (TSR in the first quintile and ROE more than 2% above the DJUI) or decreased to zero. Grants of performance shares made on December 18, 2007, allow award recipients to receive an award, as described above, but measured against the 2008 peer group rather than the DJUI for the three-year performance period ending on December 31, 2010. Restricted stock units granted on December 18, 2007 accrue dividend credits equivalent to the dividends paid on shares of PSEG Common Stock and vest one-fourth annually.

Employment Agreements

PSEG entered into an employment agreement with Mr. Izzo dated October 18, 2003, covering his employment as President and COO of PSE&G and in other executive positions to which he may be elected through October 18, 2008. The agreement provides that his base salary, target annual incentive bonus and long-term incentive bonus will be determined based on compensation practices of similar companies and that his annual salary will not be reduced during its term. The Agreement also awarded him options with respect to 500,000 shares of Common Stock, 100,000 of which vest on each October 18 from 2004 through 2008, and expire on October 18, 2013, provided he has remained continuously employed through each such vesting date.

PSEG entered into an employment agreement dated as of April 18, 2001, and amended as of December 21, 2001, with Mr. O Flynn covering his employment as Executive Vice President and Chief Financial Officer. The term of the agreement continued until July 1, 2007, with an additional year added to the term annually unless a notice of non-renewal is given by Mr. O Flynn or us at least 90 days in advance of such date. In the event of a change-in-control (as defined in such agreement), the term of Mr. O Flynn s employment is automatically continued until the second anniversary of the change-in- control. The agreement provides that Mr. O Flynn s base salary, target annual incentive bonus and long-term incentive bonus will be determined based on compensation practices of similar companies and that his annual salary will not be reduced during its term. The agreement also provided for an award to him of 200,000 shares of restricted Common Stock, which have fully vested. The agreement awarded Mr. O Flynn options with respect to the purchase of 500,000 shares of Common Stock, which are fully vested and expire on July 1, 2011. The agreement also awarded 100,000 options, which have fully vested. The agreement provides for the granting, upon the completion of five years of service, of 15 years of credit under the Mid-Career Plan for Mr. O Flynn s prior experience.

For additional information regarding severance benefit provisions in the Employment Agreements of Messrs. Izzo and O Flynn, see Potential Payments Upon Termination of Employment or Change- in-Control below.

OUTSTANDING EQUITY AWARDS AT FISCAL YEAR-END (12/31/07) TABLE*

Name

Option Awards

Stock Awards

Number of Securities Underlying Unexercised Options Exercisable (#)1

Number of Securities Underlying Unexercised Options Unexercisable (#)1

Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)

Option Exercise Price ($)

Option Expiration Date

Number of Shares or Units of Stock that have Not Vested (#)12

Market Value of Shares or Units of Stock that have Not Vested ($)13

Equity Incentive

Plan Awards: Number of Unearned Shares, Units or Other Rights that have Not Vested (#)14

Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that have Not Vested ($)13

Ralph Izzo

0

0

0

21,086

1,035,744

101,976

5,009,061

300,000

100,000

2

0

20.39

6

10/18/2013

22,000

0

0

21.38

7

05/03/2014

0

140,000

3

0

32.93

8

01/16/2017

0

113,000

4

0

39.17

9

03/20/2017

0

199,800

5

0

48.21

10

12/18/2017

E. James Ferland

0

0

0

0

0

0

0

Thomas M. O Flynn

354,000

0

0

22.93

11

07/01/2011

16,668

818,732

26,054

1,279,772

22,000

0

0

21.38

7

05/03/2014

0

82,000

3

0

32.93

8

01/16/2017

0

45,800

5

0

48.21

10

12/18/2017

R. Edwin Selover

0

0

0

11,202

550,242

17,290

849,285

0

52,000

3

0

32.93

8

01/16/2017

0

33,000

5

0

48.21

10

12/18/2017

Ralph LaRossa

0

0

0

21,086

1,035,744

101,976

5,009,061

0

52,000

3

0

32.93

8

01/16/2017

0

33,000

5

0

48.21

10

12/18/2017

Derek DiRisio

0

0

0

7,468

366,828

5,394

264,953

*

Reflects the 2-for-1 split of PSEG Common Stock effective February 4, 2008

1

Grants of non-qualified options to purchase Common Stock. The date of grant is ten years prior to the option expiration date.

2

These options vest on October 18, 2008.

3

25% of options vest on each January 16 of 2008, 2009, 2010, and 2011.

4

25% of options vest on each March 20 of 2008, 2009, 2010, and 2011.

5

25% of options vest on each December 18 of 2008, 2009, 2010, and 2011.

6

Closing price on NYSE on grant date of December 18, 2003.

7

Closing price on NYSE on grant date of May 3, 2004.

8

Closing price on NYSE on grant date of January 16, 2007.

9

Closing price on NYSE on grant date of March 20, 2007 was $39.15.

10

Closing price on NYSE on grant date of December 18, 2007.

11

Closing price on NYSE on grant date of July 1, 2001.

12

Shares of restricted stock units awarded under the LTIP, which vest as shown below. Dividends accrue at the regular dividend rate and are paid on each regular dividend payment date as declared by the Board of Directors.

Vesting Date

Grant Date

Izzo
(#)

Ferland
(#)

O Flynn
(#)

Selover
(#)

LaRossa
(#)

DiRisio
(#)

01/18/2008

01/18/2005

10,668

9,000

6,068

1,468

1,468

12/20/2008

12/20/2005

8,334

7,668

5,134

1,268

1,000

12/20/2008

10/02/2006

2,084

1,600

01/01/2008

01/16/2007

700

01/01/2009

01/16/2007

700

01/01/2010

01/16/2007

700

01/01/2011

01/16/2007

700

12/18/2008

12/18/2007

550

12/18/2009

12/18/2007

550

12/18/2010

12/18/2007

550

12/18/2011

12/18/2007

550

Mr. Ferland became fully vested upon retirement on March 31, 2007.

13

Value represents number of shares multiplied by the closing price on the NYSE on December 31, 2007 of $49.12.

14

For explanation of performance shares, see LTIP section above, following the Grants of Plan-Based Awards Table.
Mr. Ferland became fully vested upon retirement on March 31, 2007.

OPTION EXERCISES AND STOCK VESTED DURING 2007 TABLE*

Name

Option Awards

Stock Awards

Number of Shares Acquired on Exercise (#)

Value Realized on Exercise ($)1

Number of Shares Acquired on Vesting (#)2

Value Realized on Vesting ($)3

Ralph Izzo

0

0

21,084

850,391

E. James Ferland

1,420,000

28,278,627

169,350

6,777,630

Thomas M. O Flynn

0

0

16,666

663,586

R. Edwin Selover

14,666

309,754

11,200

445,679

Ralph LaRossa

3,734

77,736

4,332

185,704

Derek DiRisio

4,200

65,625

2,466

96,155

---

*

Reflects the 2-for-1 split of PSEG Common Stock effective February 4, 2008

1

Reflects difference between the exercise price and the market price on the date of exercise, multiplied by the number of shares acquired.

2

Represents: (i) the aggregate number of shares acquired from the vesting of restricted stock awards under the LTIP and (ii) the aggregate number of performance units granted under the LTIP which vested on 03/31/07, upon Mr. Ferland s retirement, as follows:

Izzo (#)

Ferland (#)

O Flynn (#)

Selover (#)

LaRossa (#)

DiRisio (#)

Restricted stock

01/18/07

10,666

43,334

9,000

6,066

1,466

1,466

03/31/07

0

110,002

0

0

0

0

12/20/07

10,418

0

7,666

5,134

2,866

1,000

Performance unitsa

03/31/07

0

16,014

0

0

0

0

3

The value attributable to the vested restricted stock is based on the closing price of PSEG Common Stock on the respective vesting dates of 01/18/07, 03/31/07 and 12/20/07 of $32.86, $41.52 and $47.99, respectively. The value attributable to the performance units, which vested on 03/31/07 upon Mr. Ferland s retirement, is based upon the closing price of PSEG Common Stock on December 31, 2007 of $49.12. These amounts are:

Izzo ($)

Ferland ($)

O Flynn ($)

Selover ($)

LaRossa ($)

DiRisio ($)

Restricted stock

01/18/07

350,431

1,423,739

295,695

199,298

48,165

48,165

03/31/07

0

4,567,283

0

0

0

0

12/20/07

499,960

0

367,891

246,381

137,539

47,990

Performance unitsa

03/31/07

0

786,608

0

0

0

---

a

Amounts shown represent the number and value of the Target Award, since the final comparative performance data necessary to calculate the final award amount is not expected to be available until March 2008.

PENSION BENEFITS TABLE

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)5	Payments During Last Fiscal Year ($)
Ralph Izzo				

Qualified Pension Plan1

15.70

295,000

0

Retirement Income Reinstatement Plan2

15.70

841,000

Mid-Career Hire Supplemental Retirement Income Plan3

3.07

546,000

Limited Supplemental Benefits Plan4

18.77

1,067,000

Total

2,749,000

E. James Ferland7

Qualified Pension Plan1

20.83

1,297,000

87,143

Retirement Income Reinstatement Plan2

20.83

3,797,000

255,044

Mid-Career Hire Supplemental Retirement Income Plan3

27.0

6,609,000

443,972

Limited Supplemental Benefits Plan4

47.83

0

0

Total

11,703,000

786,159

Thomas M. O Flynn

Qualified Pension Plan1

6.50

55,000

0

Retirement Income Reinstatement Plan2

6.50

103,000

Mid-Career Hire Supplemental Retirement Income Plan3

16.75

34,000

Limited Supplemental Benefits Plan4

23.25

2,926,000

6

Total

3,118,000

R. Edwin Selover

Qualified Pension Plan1

35.33

1,255,000

0

Retirement Income Reinstatement Plan2

35.33

2,552,000

Mid-Career Hire Supplemental Retirement Income Plan3

5.00

541,000

Limited Supplemental Benefits Plan4

40.33

459,000

Total

4,807,000

Ralph LaRossa

Qualified Pension Plan1

22.51

418,000

0

Retirement Income Reinstatement Plan2

22.51

284,000

Mid-Career Hire Supplemental Retirement Income Plan3

0

0

Limited Supplemental Benefits Plan4

22.51

0

Total

702,000

Derek DiRisio

Qualified Pension Plan1

16.31

294,000

0

Retirement Income Reinstatement Plan2

16.31

147,000

Mid-Career Hire Supplemental Retirement Income Plan3

0

0

Limited Supplemental Benefits Plan4

16.31

0

Total

441,000

1

All NEOs participate in either a traditional defined benefit pension plan (Pension Plan) or a cash balance pension plan (Cash Balance Plan), depending on date of hire, each of which is a qualified plan under the IRC. Such plans are available to all other employees under the same terms and conditions. Messrs. Izzo, Ferland, Selover, LaRossa and DiRisio participate in the pension plan. Mr. O Flynn participates in the cash balance plan. Years shown reflect actual years of service.

2

Years shown reflect actual years of service.

3

Certain employees receive additional years of credited service for the purpose of retirement benefit calculations in recognition of prior work experience before joining the Company, including 22 years for Mr. Ferland and 15 years for Mr. O Flynn, pursuant to their respective employment agreements. In addition, participants receive an additional 5 years which vest at age 60 as described below under Mid-Career Plan.

4

Years shown reflect the sum of actual years of service and years credited under the Mid-Career Hire Supplemental Retirement Income Plan.

5

Amounts shown represent actuarial present value of accumulated benefit computed as of the same pension plan measurement date used for PSEG s financial statements for the year ended December 31, 2007, with two exceptions: (i) NEOs were assumed to retire at the earliest point at which the benefits were payable on an unreduced basis in the plan providing the largest target benefit and (ii) no pre-retirement termination, disability or death was assumed to occur. For a discussion of the valuation method and material assumptions applied in quantifying the present value, see Note 16 Pension, OPEB and Savings Plans.

6

The actuarial present value of accumulated benefits based on actual years of service is $1,915,000 and the actuarial present value of accumulated benefits based on additional years of service is $1,011,000.

7

Mr. Ferland retired on March 31, 2007.

Qualified Pension Plans

All of our employees are eligible to participate in either a Pension Plan or a Cash Balance Plan. The Pension Plan covers employees hired prior to January 1, 1996 and provides participants with a life annuity benefit at normal retirement (age 65) pursuant to a formula based upon (a) the participant s number of years of service and (b) the average of the participant s five highest years of compensation after December 21, 1994 up to the limit imposed by the IRC.

The benefit formula is A + B + C:

A

=

1.3% of the lesser of 5-year final average earnings not in excess of $24,600 times years of credited service not exceeding 35 years,

B

=

1.5% of the amount by which 5-year final average earnings exceeds $24,600 times years of credited service not exceeding 35 years,

C

=

1.5% of 5-year final average earnings times years of credited service in excess of 35 years.

An additional benefit equal to $4.00 per month for each year of credited service is payable until the retiree reaches age 65.

Participants become fully vested in their Pension Plan benefit upon completion of five years of service. Benefits are payable on an unreduced basis (i) at age 65, (ii) at age 60, if the participant s age, plus years of service, equals or exceeds 80 or (iii) at age 55, if the participant has 25 or more years of service. Participants whose age, plus years of service, equals or exceeds 80, but who are not yet age 55, may commence their Pension Plan benefits on a reduced basis.

The Cash Balance Plan covers employees hired or rehired on or after January 1, 1996 and provides each participant with a life annuity benefit at normal retirement (age 65) equal to the actuarial equivalent of a notational amount maintained for him/her. Participants are eligible for retirement under the Cash Balance Plan upon the attainment of age 55 with five or more years of service. Participants accounts are credited each year with a percentage of compensation, which is determined based on the participant s age plus years of service measured at year-end.

Sum of Age and Service	**Percentage of Compensation Credited**
<30	2.00 %
30 39	2.50 %
40 49	

3.25

%

50 59

4.25

%

60 69

5.50

%

70 79

7.00

%

80 89

9.00

%

90+

12.00

%

Each participant s notional amount grows each year with interest credits based on a 6.0% annual rate of interest. Participants become immediately fully vested in their Cash Balance Plan benefit.

Reinstatement Plan

All employees are eligible to participate in a non-qualified excess benefit retirement plan, the Retirement Income Reinstatement Plan for Non-Represented Employees (Reinstatement Plan), designed to replace earned pension benefits as determined by the qualified pension formula, but which are not eligible for payment from the qualified pension plans as a result of IRC mandated limits for qualified plans. The benefits payable under this plan mirror those of the qualified plans described above except that the compensation considered in computing the benefit (i) will not be limited by qualified plan limits, (ii) will include any amounts that the participant may have deferred under deferred compensation plans, (iii) will include amounts earned under MICP (which are not considered under the qualified pension plans), (iv) will be limited to 150% of average base salary for the applicable five years and (v) will be offset by any benefits received by the participant under the qualified plan.

Mid-Career Plan

Certain employees receive additional years of service for the purpose of retirement benefit calculations in recognition of prior work experience. Such benefits are paid from a non-qualified plan, the Mid-Career Hire Supplemental Retirement Income Plan (Mid-Career Plan). Under the Mid-Career Plan, certain participants, including the NEOs, receive an additional five years of credited service for the purpose of pension benefit calculations if they retire between ages 60 and 65. The credited years of service reduce by one year for each six-month period such participant works beyond age 65. This feature of the plan is designed to encourage retirement on or before age 65. Benefits payable under the Mid-Career Plan mirror those payable under the Reinstatement Plan, except that the additional years of service are considered in calculating the amount of benefit. Any benefit payable under this plan is offset by benefits payable under the qualified plan and the Reinstatement Plan.

Limited Plan

Certain employees, including the NEOs participate in a limited non-qualified supplemental retirement plan, the Limited Supplemental Benefits Plan for Certain Employees (Limited Plan). This plan seeks to provide a total target replacement income percentage equal to credited service for qualified pension calculation purposes, Mid-Career Plan calculation purposes plus 30 to a maximum of 75%. Compensation covered for the Limited Plan is the same as for the Mid-Career Plan. The target replacement amount under the Limited Plan is reduced by any pension benefits accrued and vested from a previous employer at the time of hire, by the participant s Social Security benefit at normal retirement age and by the pension benefits provided by each other PSEG retirement benefit plan (qualified plans and non-qualified plans). The Limited Plan also provides a death benefit equal to 150% of base compensation if death occurs while the participant is actively employed. Participants become entitled to a Limited Plan benefit only upon (a) retirement under the terms of the qualified plan in which they participate (Pension Plan or Cash Balance Plan) or (b) death, at which point the benefit is payable as an annuity on an unreduced basis.

NON-QUALIFIED DEFERRED COMPENSATION TABLE

Name	Executive Contributions in Last Fiscal Year (2007) ($)	Registrant Contributions in Last Fiscal Year (2007) ($)	Aggregate Earnings in Last Fiscal Year (2007) ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last Fiscal Year End (12/31/07) ($)
Ralph Izzo1					

437,600

0

112,040

0

1,375,423

E. James Ferland2

3,337,506

0

708,847

909,876

8,299,001

Thomas M. O Flynn3

437,600

0

60,523

0

885,368

R. Edwin Selover4

298,386

0

118,016

0

1,520,103

Ralph LaRossa

0

0

0

0

0

Derek DiRisio

0

0

0

0

0

1

The amount shown under Executive Contributions in Last Fiscal Year (2007) was previously reported in our 2006 10-K. $37,930 of the amount shown under Aggregate Earnings in Last Fiscal Year (2007) is reported in the Summary Compensation Table in this report under Change in Pension Value and Non-Qualified Deferred Compensation as earnings in excess of 120% of the applicable long-term rate as discussed in footnote 7 of that Table. $1,178,479 of the amount shown under Aggregate Balance at Last Fiscal Year End (12/31/07) is reported in the Summary Compensation Table for the Last Fiscal Year in this report or in reports for previous years.

2

The amount shown under Executive Contributions in Last Fiscal Year (2007) was previously reported in our 2006 10-K. $239,158 of the amount shown under Aggregate Earnings in Last Fiscal Year (2007) is reported in this report in the Summary Compensation Table under Change in Pension Value and Non-

Qualified Deferred Compensation as earnings in excess of 120% of the applicable long-term rate as discussed in footnote 7 of that Table. $5,855,170 of the amount shown under Aggregate Balance at Last Fiscal Year End (12/31/07) is reported in the Summary Compensation Table for the Last Fiscal Year in this report or in reports for previous years.

3

The amount shown under Executive Contributions in Last Fiscal Year (2007) was previously reported in our 2006 10-K. $13,363 of the amount shown under Aggregate Earnings in Last Fiscal Year (2007) is reported in the Summary Compensation Table in this report under Change in Pension Value and Non-Qualified Deferred Compensation as earnings in excess of 120% of the applicable long-term rate as discussed in footnote 7 of that Table. $768,406 of the amount shown under Aggregate Balance at Last Fiscal Year End (12/31/07) is reported in the Summary Compensation Table for the Last Fiscal Year in this report or in reports for previous years.

4

The amount shown under Executive Contributions in Last Fiscal Year (2007) is reflected in the Summary Compensation Table in this report. $39,787 of the amount shown under Aggregate Earnings in Last Fiscal Year (2007) is reported in the Summary Compensation Table in this report under Change in Pension Value and Non-Qualified Deferred Compensation as earnings in excess of 120% of the applicable long-term rate as discussed in footnote 7 of that Table. $438,332 of the amount shown under Aggregate Balance at Last Fiscal Year End (12/31/07) is reported in the Summary Compensation Table for the Last Fiscal Year in this report or in reports for previous years.

Deferred Compensation Plan

Under the PSEG Deferred Compensation Plan for Certain Employees (Deferred Compensation Plan), participants, including the NEOs, may elect to defer any portion of their compensation by making appropriate elections in the calendar year prior to the year in which the services giving rise to the compensation being deferred is rendered. For performance-based compensation, elections may be made up to the date that is six months before the end of the related performance period, as long as (a) the performance period is at least 12 months in length, (b) the participant performed services continuously from the date the performance criteria were established through the date the deferral election is made and (c) at the time the deferral election is made, the performance-based compensation is not both (i) substantially certain to be paid and (ii) readily ascertainable. A participant may change an election to defer compensation not later than the date that is the last date that an election to defer may be made.

At the same time he/she elects to defer compensation, the participant must make an election as to the timing and the form of distribution from his/her Deferred Compensation Plan account. Distributions may commence (a) on the thirtieth day after the date he/she terminates employment or, in the alternative, (b) on January 15th of any calendar year following termination of employment elected by him/her, but in any event no later than the later of (i) the January of the year following the year of his/her 70th birthday or (ii) the January following termination of employment. Notwithstanding the forgoing, however, for NEOs, distribution of his/her account may not occur earlier than six months following the date of his/her termination of service. Participants may elect to receive the distribution of their Deferred Compensation account in the form of (x) one lump-sum payment, (y) annual distributions over a five-year period or (z) annual distributions over a 10-year period.

Participants may make changes of distribution elections on a prospective basis. Participants may also make changes of distribution elections with respect to prior deferred compensation as long as (a) any such new distribution election is made at least one year prior to the date that the commencement of the distribution would otherwise have occurred and (b) the revised commencement date is at least five years later than the date that the commencement of the distribution would otherwise have occurred.

Amounts deferred under the Deferred Compensation Plan are credited with earnings based on (i) the performance of one or more of the pre-mixed lifestyle investment portfolio funds or the S&P 500 Fund available to employees under our 401(k) Plans or (ii) at the rate of Prime plus 1/2%, in such percentages as selected by the participant. A participant who fails to provide a designation of investment funds will accrue earnings on his/her account at the rate of Prime plus 1/2%.

For 2007 the rates of return for these funds were as follows:

Conservative Pre-Mixed Portfolio	5.66 %
Moderate Pre-Mixed Portfolio	6.12 %
Aggressive Pre-Mixed Portfolio	6.09 %
S&P 500 Fund	

5.40

%

Prime Plus 1/2%

9.03

%

A participant may change fund selection once a year.

POTENTIAL PAYMENTS UPON TERMINATION OF EMPLOYMENT OR CHANGE-IN-CONTROL

The employment agreements of Messrs. Izzo and O Flynn discussed above each provide for certain severance benefits. Each of these agreements provides that if the individual is terminated without cause (a willful failure to perform his duties) or resigns for good reason (a reduction in pay, position or authority) during the term of such agreement, the respective entire restricted stock award and/or entire option award becomes vested, the individual will be paid a benefit of two times base salary and target bonus, and his welfare benefits will be continued for two years unless he is sooner employed. In the event such a termination occurs after a change-in-control (as defined below), the payment to the individual becomes three times the sum of salary and target bonus, continuation of welfare benefits for three years unless sooner reemployed, payment of the net present value of providing three years additional service under our retirement plans and a gross-up for excise taxes due under the IRC on any termination payments. Each of the agreements provides that the individual is prohibited for one year from competing with and for two years from recruiting employees from us or its subsidiaries or affiliates, after termination of employment. Violations of these provisions require a forfeiture of the respective restricted stock and option grants and certain benefits.

PSEG s Key Executive Severance Plan provides severance benefits to Messrs. Selover, LaRossa and DiRisio and to certain of our key executive-level employees whose employment is terminated without cause after a change-in-control.

Under the Key Executive Severance Plan, if any of Messrs. Selover, LaRossa or DiRisio is terminated without cause or resigns his employment for good reason within two years after a change-in- control, he will receive (1) a pro rata bonus based on his target annual incentive compensation, (2) three times the sum of his salary and target incentive bonus, (3) accelerated vesting of equity-based awards, (4) a lump sum payment equal to the actuarial equivalent of his benefits under all of our retirement plans in which he participates calculated as though he remained employed for three years beyond the date his employment terminates less the actuarial equivalent of such benefits on the date his employment terminates, (5) three years continued welfare benefits (the first 18 months of which will be provided through PSEG-paid COBRA continuation coverage), (6) one year of PSEG-paid outplacement services and (7) vesting of any compensation previously deferred.

Messrs. Selover, LaRossa and DiRisio also participate in PSEG s Separation Allowance Benefit Plan for Non-Represented Employees (Separation Allowance Plan) which provides certain severance benefits to non-represented employees who suffer a termination of employment as a result of a reduction in force or reorganization. Under the Separation Allowance Plan, key managers, including Messrs. Selover, LaRossa and DiRisio are entitled to two weeks of base salary for each year of service, with a minimum of 26 weeks and a maximum of 52 weeks of base salary, as well as a prorated payment of their target incentive award and certain outplacement services, educational assistance, health care and life insurance coverage.

If a termination without cause, with good reason or for a reduction in force or reorganization had occurred on December 31, 2007, each of the NEOs would have received the following benefits:

Izzo

$

12,857,859

O Flynn

$

4,800,635

Selover

$

2,409,213

LaRossa

$

1,825,499

DiRisio

$

618,369

If a termination without cause or with good reason had occurred on December 31, 2007 following a change-in-control, each of the NEOs would have received the following benefits:

Izzo	$	20,564,901
O Flynn	$	6,164,611
Selover	$	4,423,523

LaRossa

$

4,972,637

DiRisio

$

1,344,566

Change-in-Control under the Employment Agreements of Mr. Izzo and Mr. O Flynn and under the Key Executive Severance Plan generally means the occurrence of any of the following events:

(a) any person is or becomes the beneficial owner of our securities representing 25% or more of the combined voting power of our then outstanding securities; or

(b) a majority of the Board of Directors is replaced without approval of the current Board; or

(c) there is consummated a merger or consolidation of us, other than a merger or consolidation which would result in our voting securities outstanding immediately prior to such merger continuing to represent at least 75% of the combined voting power of the securities of us or such surviving entity immediately after such merger or consolidation; or

(d) our shareholders approve a plan of complete liquidation or dissolution of us or there is consummated an agreement for the sale or disposition by us of all or substantially all of our assets.

DIRECTOR COMPENSATION TABLE

Name

Fees Earned or Paid In Cash ($)1

Stock Awards ($)2

Option Awards ($)

Non-Equity Incentive Plan Compensation

($)

Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)

All Other Compensation ($)

Total ($)

Caroline Dorsa

84,500

67,375

0

0

0

0

151,875

Albert R. Gamper, Jr.

100,500

67,375

0

0

0

0

167,875

Conrad K. Harper

92,000

67,375

0

0

0

0

159,375

1

Includes all meeting fees, chair/committee retainer fees and the annual retainer. During 2007, each director who was not an officer of us or our subsidiaries and affiliates was paid an annual retainer of $45,000 and a fee of $1,500 for attendance at any Board or committee meeting, inspection trip, conference or other similar activity relating to us or PSE&G. No additional retainer is paid for service as a director of PSE&G. Each Committee Chair received an additional annual retainer of $5,000, except for the Chair of the Audit Committee, who received $15,000 and the Chair of the Organization and Compensation Committee who received $10,000. In addition, each member of the Audit Committee received an additional annual retainer of $5,000.

2

Amount shown reflects the expense included on PSEG s Financial Statements for 2007 related to awards under the 2007 Equity Compensation Plan for Outside Directors (Directors Equity Plan) granted on May 1, 2007 and still outstanding as determined under SFAS 123R. The Directors Equity Plan is a deferred compensation plan and, under its terms, each outside director is granted an award of stock units each May 1st (in an amount determined from time-to-time by the Board) which is recorded in a bookkeeping account in her/his name and accrues earnings credits equivalent to the earnings on shares of PSEG Common Stock. If a director fails to remain as a member of the Board (other than on account of disability or death) until the earlier of the succeeding April 30th or the next Annual Meeting of Stockholders, the award for that year will be prorated to reflect actual service. Distributions under the Directors Equity Plan are made in shares of PSEG Common Stock after the director terminates service on the Board in accordance with distribution elections made by her/him.

For each outside director the grant date fair value of the award was $100,000 on May 1, 2007, which equated to 2,306 stock units based on the then-current market price of the Common Stock. In addition, each outside director s account is credited with additional stock units on the quarterly dividend dates at the then current dividend rate. For a discussion on the assumptions made in valuation, see Note 17. Stock Based Compensation.

Directors Deferred Compensation Plan

Under PSEG Deferred Compensation Plan for Directors (Directors Deferred Compensation Plan), directors who are not employees may elect to defer any portion of their retainer and meeting attendance fees by making appropriate elections in the calendar year prior to the year in which the services giving rise to the compensation being deferred is rendered. A participant may change an election to defer compensation not later than the date that is the last date that an election to defer may be made.

At the same time he/she elects to defer compensation, the participant must make an election as to the timing and the form of distribution from his/her Directors Deferred Compensation Plan account. Distributions may commence (a) on the thirtieth day after the date he/she terminates service as a director or, in the alternative, (b) on January 15th of any calendar year following termination of service elected by him/her, but in any event no later than the later of (i) the January of the year following the year of his/her 71st birthday or (ii) the January following termination of service. Participants may elect to receive distribution of their Directors Deferred Compensation account in the form of (x) one lump-sum payment, or (y) annual distributions over a period selected by the participant, up to 10 years. Restricted stock awarded to directors pursuant to stock plan for outside directors. The shares are subject to forfeiture if the director leaves prior to age 72.

The following table shows outstanding stock units and restricted shares as of December 31, 2007 adjusted for the stock split:

Dorsa
(#)

Gamper
(#)

Harper
(#)

Stock units

2,306

2,306

2,306

Restricted stock

8,800

9,600

13,200

Participants may make changes of distribution elections on a prospective basis. Participants may also make changes of distribution elections with respect to prior deferred compensation as long as (A) any such new distribution election is made at least one year prior to the date that the commencement of the distribution would otherwise have occurred and (B) the revised commencement date is at least five years later than the date that the commencement of the distribution would otherwise have occurred.

Amounts deferred under the Directors Deferred Compensation Plan are credited with earnings based on (i) the performance of one or more of the pre-mixed lifestyle investment portfolio funds or the S&P 500 fund available to employees under the Company s 401(k) Plans, (ii) at the rate of Prime plus 1/2% or (iii) by reference to the performance of the Company s Common Stock, in such percentages designated by the participant. A participant who fails to provide a designation will accrue earnings on his/her account at the rate of Prime plus 1/2%.

For 2007, the rates of return for these funds were as follows:

Conservative Pre-Mixed Portfolio

5.66

%

Moderate Pre-Mixed Portfolio

6.12

%

Aggressive Pre-Mixed Portfolio

6.09

%

S&P 500 Fund

5.40

%

Prime Plus 1/2%

9.03

%

PSEG Common Stock

50.35

%

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

PSE&G does not have a compensation committee. Decisions regarding compensation of PSE&G s executive officers are made by the Organization and Compensation Committee of PSEG. During 2007, each of the following individuals served as a member of the Organization and Compensation Committee: Shirley Ann Jackson, Chair, Ernest H. Drew, Albert R. Gamper, Jr., Conrad K. Harper, William V. Hickey, Thomas A. Renyi and Richard J. Swift. During 2007, no member of the Organization and Compensation Committee was an officer or employee or a former officer or employee of any PSEG company. No PSEG officer served as a director of or on the compensation committee of any of the companies for which any of these individuals served as an officer. Other than as described below under Transactions With Related Persons, no member of the Organization and Compensation Committee had a direct or indirect material interest in any transaction with us.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

PSEG

The information required by Item 12 of Form 10-K with respect to directors, executive officers and certain beneficial owners is set forth under the heading Security Ownership of Directors, Management and Certain Beneficial Owners in PSEG s definitive Proxy Statement for the 2008 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 5, 2008, and such information set forth under such heading is incorporated herein by this reference thereto.

For information relating to securities authorized for issuance under equity compensation plans, see Item 5. Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Power

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

PSE&G

The following table sets forth, as of February 15, 2008, the record date, beneficial ownership of Common Stock, including options, by the directors and executive officers named in the Summary Compensation Table. None of these amounts exceeds 1% of the Common Stock outstanding.

Name

Amount and Nature of Beneficial Ownership*

Derek DiRisio

12,818

1

Caroline Dorsa

13,560

2

E. James Ferland

588,252

3

Albert R. Gamper, Jr.

15,282

4

Conrad K. Harper

21,932

5

Ralph Izzo

1,017,222

6

Ralph LaRossa

92,827

7

Thomas M. O Flynn

634,229

8

R. Edwin Selover

131,428

9

All directors and executive officers as a group (9 persons)

2,527,550

10

1

Includes 3,100 shares of restricted stock. Includes 2,532 shares held under the Thrift Plan. Includes 360 shares jointly held with wife.

2

Includes 8,800 shares of restricted stock. Includes 1,000 shares jointly owned with husband.

3

Includes the equivalent of 42 shares held under the Thrift Plan. Includes 378,000 shares held in a trust. Mr. Ferland retired effective March 31, 2007.

4

Includes 9,600 shares of restricted stock.

5

Includes 13,200 shares of restricted stock.

6

Includes the equivalent of 702 shares held under the Thrift Plan. Includes 10,418 shares of restricted stock. Includes options to purchase 874,800 shares, 322,000 of which are currently exercisable. Includes 131,302 shares held in a trust.

7

Includes 2,868 shares of restricted stock. Includes options to purchase 85,000 shares, none of which are currently exercisable.

8

Includes the equivalent of 32 shares held under the Thrift Plan. Includes 7,668 shares of restricted stock. Includes options to purchase 503,800 shares, 376,000 of which are currently exercisable.

9

Includes the equivalent of 24 shares under the Thrift Plan. Includes 5,134 shares of restricted stock. Includes options to purchase 85,000 shares, 13,000 of which are exercisable.

10

Includes the equivalent of 3,332 shares held under the Thrift Plan. Includes 60,788 shares of restricted stock. Includes options to purchase 1,548,600 shares, 711,000 of which are currently exercisable. Includes 509,302 shares held in trusts. Includes 1,360 shares jointly owned with spouses.

*

Reflects the 2-for-1 split of PSEG Common Stock effective February 4, 2008.

Certain Beneficial Owners

The following table sets forth, as of February 15, 2008, beneficial ownership by any person or group known to us to be the beneficial owner of more than five percent of the Common Stock. According to the Schedule 13G filed with the SEC, these securities were acquired and are held in the ordinary course of business and not for the purpose of changing or influencing the control of the Company.

Name and Address

Amount and Nature of Beneficial Ownership

Percent

Franklin Resources, Inc.

One Franklin Parkway

San Mateo, CA 94403-1906

26,427,4001

5.21

1

As reported on Schedule 13G/A filed February 20, 2008

Section 16 Beneficial Ownership Reporting Compliance

During 2007, none of our directors or executive officers was late in filing a Form 3, 4 or 5 in accordance with the requirements of Section 16(a) of the Securities Exchange Act of 1934, as amended, with regard to transactions involving Common Stock.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

PSEG

The information required by Item 13 of Form 10-K is set forth under the heading Transactions with Related Persons in PSEG s definitive Proxy Statement for the 2008 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 3, 2008. Such information set forth under such heading is incorporated herein by this reference thereto.

Power

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

PSE&G

Transactions with Related Persons

Except as stated below, there were no transactions during 2007, and there are no transactions currently proposed, in which PSE&G was or is to be a participant and the amount involved exceeded $120,000 and in which any related person (director, nominee, executive officer, or their immediate family members) had or will have a direct or indirect material interest.

Thomas A. Renyi, a director of PSE&G, is Executive Chairman of the Board of The Bank of New York Mellon Corporation (BNY), a participant in three credit facilities of PSEG and its subsidiaries. Each of these facilities, and BNY s participation, was made in the ordinary course of business, on substantially the same terms, including interest rates and collateral, as those prevailing at the time for comparable loans with persons not related to BNY, and did not involve more than the normal risk of collectibility or present other unfavorable features.

212

Our policies and procedures with regard to transactions with related parties, including the review, approval or ratification of any such transactions, the standards applied and the responsibilities for application are set forth in the Corporate Governance Principles and the Standards of Integrity, discussed above. These are our only written policies and procedures regarding the review, approval or ratification of transactions with related persons.

Under the Corporate Governance Principles, a director of PSE&G must notify the Chair of the PSEG Corporate Governance Committee if he or she encounters a conflict of interest or proposes to accept a position with an entity which may present a conflict of interest, so that the issue may be reviewed. Potential conflicts of interest include positions that directors or immediate family members hold as directors, officers or employees of other companies with which we do business or propose to do business and charitable and other tax-exempt organizations to which we contribute or propose to contribute. The Standards of Integrity establish expectations for behavior for directors, officers and employees regarding, among other things, corporate opportunity, conflict of interest, and customer, supplier, competitor and governmental relations. The Standards of Integrity establish a procedure for seeking guidance, reporting concerns, investigation and discipline.

Director Independence

The Board has determined that all of the current directors, except Ralph Izzo, the Chairman of the Board, President and CEO who is an employee of the Company, are independent under the Corporate Governance Principles and the requirements of the NYSE. Similarly, E. James Ferland, who served as Chairman of the Board and CEO until March 31, 2007, was not independent under these criteria as he was an employee of the Company. These determinations were based upon a review of the questionnaires submitted by each director, our relevant business records, publicly available information and the applicable SEC and NYSE requirements.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by Item 14 of Form 10-K is set forth under the heading Fees Billed to PSEG by Deloitte & Touche LLP for 2007 and 2006 in PSEG s definitive Proxy Statement for the 2008 Annual Meeting of Stockholders which definitive Proxy Statement is expected to be filed with the SEC on or about March 5, 2008. Such information set forth under such heading is incorporated herein by this reference thereto.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(A)

The following Financial Statements are filed as a part of this report:

a.

Public Service Enterprise Group Incorporated s Consolidated Balance Sheets as of December 31, 2007 and 2006 and the related Consolidated Statements of Operations, Cash Flows and Common Stockholders Equity for the three years ended December 31, 2007 on pages 90 and 91, 89, 92 and 93, respectively.

b.

PSEG Power LLC s Consolidated Balance Sheets as of December 31, 2007 and 2006 and the related Consolidated Statements of Operations, Cash Flows and Capitalization and Member s Equity for the three years ended December 31, 2007 on pages 95, 94, 96 and 97, respectively.

c.

Public Service Electric and Gas Company s Consolidated Balance Sheets as of December 31, 2007 and 2006 and the related Consolidated Statements of Operations, Cash Flows and Common Stockholder s Equity for the three years ended December 31, 2007 on pages 100 and 101, 99, 102 and 103, respectively.

(B)

The following documents are filed as a part of this report:

a.

PSEG s Financial Statement Schedules:

Schedule II Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2007 (page 214).

b.

Power s Financial Statement Schedules:

Schedule II Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2007 (page 215).

c.

PSE&G s Financial Statement Schedules:

Schedule II Valuation and Qualifying Accounts for each of the three years in the period ended December 31, 2007 (page 215).

Schedules other than those listed above are omitted for the reason that they are not required or are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(C) The following documents are filed as part of this report:

LIST OF EXHIBITS:

a.

PSEG:

3a

Certificate of Incorporation Public Service Enterprise Group Incorporated1

3b

By-Laws of Public Service Enterprise Group Incorporated as in effect April 20, 20072

3c

Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 23, 19873

3d

Certificate of Amendment of Certificate of Incorporation of Public Service Enterprise Group Incorporated, effective April 20, 20074

4a(1)

Indenture between Public Service Enterprise Group Incorporated and First Union National Bank (US Bank National Association, successor), as Trustee, dated January 1, 1998 providing for Deferrable Interest Subordinated Debentures in Series (relating to Quarterly Preferred Securities)5

9

Inapplicable

10a(1)

Amended and Restated Limited Supplemental Benefits Plan for Certain Employees

10a(2)

Mid Career Hire Supplemental Retirement Income Plan

10a(3)

Retirement Income Reinstatement Plan for Non-Represented Employees

10a(4)

Employment Agreement with William Levis dated December 8, 2006

10a(5)

2007 Equity Compensation Plan for Outside Directors

10a(6)

Employee Stock Purchase Plan6

10a(7)

Deferred Compensation Plan for Directors7

10a(8)

Deferred Compensation Plan for Certain Employees8

10a(9)

1989 Long-Term Incentive Plan, as amended9

10a(10)

2001 Long-Term Incentive Plan10

10a(11)

Restated and Amended Management Incentive Compensation Plan11

10a(12)

Employment Agreement with Thomas M. O Flynn dated April 18, 200112

10a(13)

Amendment to Employment Agreement with Thomas M. O Flynn dated December 21, 200113

10a(14)

Key Executive Severance Plan14

10a(15)

Employment Agreement with Ralph Izzo dated October 18, 200315

10a(16)

Stock Plan for Outside Directors, as amended16

10a(17)

Compensation Plan for Outside Directors17

10a(18)

2004 Long-Term Incentive Plan18

10b(1)

Operating Services Contract19

11

Inapplicable

12

Computation of Ratios of Earnings to Fixed Charges

13

Inapplicable

14

Code of Ethics

16

Inapplicable

18

Inapplicable

21

Subsidiaries of the Registrant

22

Inapplicable

23

Consent of Independent Registered Public Accounting Firm

24

Inapplicable

31a

Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the Securities Exchange Act of 1934 (1934 Act)

31b

Certification by Thomas M. O Flynn pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

32a

Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

32b

Certification by Thomas M. O Flynn, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

b.

Power:

3a

Certificate of Formation of PSEG Power LLC20

3b

PSEG Power LLC Limited Liability Company Agreement21

3c

Trust Agreement for PSEG Power Capital Trust I22

3d

Trust Agreement for PSEG Power Capital Trust II23

3e

Trust Agreement for PSEG Power Capital Trust III24

3f

Trust Agreement for PSEG Power Capital Trust IV25

3g

Trust Agreement for PSEG Power Capital Trust V26

4a

Indenture dated April 16, 2001 between and among PSEG Power, PSEG Fossil, PSEG Nuclear, PSEG Energy Resources & Trade and The Bank of New York and form of Subsidiary Guaranty included therein27

4b

First Supplemental Indenture, supplemental to Exhibit 4a, dated as of March 13, 200228

10a(1)

Amended and Restated Limited Supplemental Benefits Plan for Certain Employees

10a(2)

Mid Career Hire Supplemental Retirement Income Plan

10a(3)

Retirement Income Reinstatement Plan for Non-Represented Employees

10a(4)

Employment Agreement with William Levis dated December 8, 2006

10a(6)

Employee Stock Purchase Plan6

10a(7)

Deferred Compensation Plan for Certain Employees8

10a(8)

1989 Long-Term Incentive Plan, as amended9

10a(9)

2001 Long-Term Incentive Plan10

10a(10)

Restated and Amended Management Incentive Compensation Plan11

10a(11)

Employment Agreement with Thomas M. O Flynn dated April 18, 200112

10a(12)

Amendment to Employment Agreement with Thomas M. O Flynn dated December 21, 200113

10a(13)

Key Executive Severance Plan29

10a(14)

Employment Agreement with Ralph Izzo dated October 18, 200315

10a(15)

2004 Long-Term Incentive Plan18

10b(1)

Operating Services Contract19

11

Inapplicable

12c

Computation of Ratio of Earnings to Fixed Charges

13

Inapplicable

14

Code of Ethics

16

Inapplicable

18

Inapplicable

19

Inapplicable

23

Consent of Independent Registered Public Accounting Firm

24

Inapplicable

31e

Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

31f

Certification by Thomas M. O Flynn pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

32e

Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

32f

Certification by Thomas M. O Flynn, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

c.

PSE&G

3a(1)

Restated Certificate of Incorporation of PSE&G30

3a(2)

Certificate of Amendment of Certificate of Restated Certificate of Incorporation of PSE&G filed February 18, 1987 with the State of New Jersey adopting limitations of liability provisions in accordance with an amendment to New Jersey Business Corporation Act31

3a(3)

Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed June 17, 1992 with the State of New Jersey, establishing the 7.44% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock32

3a(4)

Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed March 11, 1993 with the State of New Jersey, establishing the 5.97% Cumulative Preferred Stock ($100 Par) as a series of Preferred Stock33

3a(5)

Certificate of Amendment of Restated Certificate of Incorporation of PSE&G filed January 27, 1995 with the State of New Jersey, establishing the 6.92% Cumulative Preferred Stock ($100 Par) and the 6.75% Cumulative Preferred Stock $25 Par as series of Preferred Stock34

3b(1)

By-Laws of PSE&G as in effect April 17, 200735

4a(1)

Indenture between PSE&G and Fidelity Union Trust Company (now, Wachovia Bank, National Association), as Trustee, dated August 1, 1924, securing First and Refunding Mortgage Bond36 Indentures between PSE&G and First Fidelity Bank, National Association (US Bank National Association, successor), as Trustee, supplemental to Exhibit 4a(1), dated as follows:

4a(2)

April 1, 192737

4a(3)

June 1, 193738

4a(4)

July 1, 193739

4a(5)

December 19, 193940

4a(6)

March 1, 194241

4a(7)

June 1, 1991 (No. 1)42

4a(8)

July 1, 199343

4a(9)

September 1, 199344

4a(10)

February 1, 199445

4a(11)

March 1, 1994 (No. 2)46

4a(12)

May 1, 199447

4a(13)

October 1, 1994 (No. 2)48

4a(14)

January 1, 1996 (No. 1)49

4a(15)

January 1, 1996 (No. 2)50

4a(16)

May 1, 199851

4a(17)

September 1, 200252

4a(18)

August 1, 200353

4a(19)

December 1, 2003 (No. 1)54

4a(20)

December 1, 2003 (No. 2)55

4a(21)

December 1, 2003 (No. 3)56

4a(22)

December 1, 2003 (No. 4)57

4a(23)

June 1, 200458

4a(24)

August 1, 2004 (No. 1)59

4a(25)

August 1, 2004 (No. 2)60

4a(26)

August 1, 2004 (No. 3)61

4a(27)

August 1, 2004 (No. 4)62

4a(28)

April 1, 2007

4b

Indenture of Trust between PSE&G and Chase Manhattan Bank (National Association) (The Bank of New York, successor), as Trustee, providing for Secured Medium-Term Notes dated July 1, 199363

4c

Indenture dated as of December 1, 2000 between Public Service Electric and Gas Company and First Union National Bank (US Bank National Association, successor), as Trustee, providing for Senior Debt Securities64

10a(1)

Amended and Restated Limited Supplemental Benefits Plan for Certain Employees

10a(2)

Mid Career Hire Supplemental Retirement Income Plan

10a(3)

Retirement Income Reinstatement Plan for Non-Represented Employees

10a(5)

2007 Equity Compensation Plan for Outside Directors

10a(6)

Employee Stock Purchase Plan6

10a(7)

Deferred Compensation Plan for Directors7

10a(8)

Deferred Compensation Plan for Certain Employees8

10a(9)

1989 Long-Term Incentive Plan, as amended9

10a(10)

2001 Long-Term Incentive Plan10

10a(11)

Restated and Amended Management Incentive Compensation Plan11

10a(12)

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10a(13)

Amendment to Employment Agreement with Thomas M. O Flynn dated December 21, 200113

10a(14)

Key Executive Severance Plan65

10a(15)

Employment Agreement with Ralph Izzo dated October 18, 200315

10a(16)

Stock Plan for Outside Directors, as amended16

10a(17)

Compensation Plan for Outside Directors17

10a(18)

2004 Long-Term Incentive Plan18

11

Inapplicable

12a

Computation of Ratios of Earnings to Fixed Charges

12b

Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements

13

Inapplicable

14

Code of Ethics

16

Inapplicable

18

Inapplicable

19

Inapplicable

21a

Inapplicable

23a

Consent of Independent Registered Public Accounting Firm

24

Inapplicable

31c

Certification by Ralph Izzo, pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

31d

Certification by Thomas M. O Flynn pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

32c

Certification by Ralph Izzo, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

32d

Certification by Thomas M. O Flynn, pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

(1)

Filed as Exhibit 3.1a with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.

(2)

Filed as Exhibit 3.2 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.

(3)

Filed as Exhibit 3.1b with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.

(4)

Filed as Exhibit 3.1c with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-09120 on May 4, 2007 and incorporated herein by this reference.

(5)

Filed as Exhibit 4(f) with Quarterly Report on Form 10-Q for the quarter ended March 31, 1998, File No. 001-09120 on May 13, 1998 and incorporated herein by this reference.

(6)

Filed with Registration Statement on Form S-8, File No. 333-106330 filed on June 20, 2003 and incorporated herein by this reference.

(7)

Filed as Exhibit 10a(1) with Annual Report on Form 10-K for the year ended December 31, 2005, File Nos. 001-09120 and 001-00973, and incorporated herein by reference.

(8)

Filed as Exhibit 10a(2) with Annual Report on Form 10-K for the year ended December 31, 2005, File Nos. 001-09120 and 001-00973 and incorporated herein by reference.

(9)

Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2002, File No. 001-09120, on November 2, 2002 and incorporated herein by this reference.

(10)

Filed as Exhibit 10a(7) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.

(11)

Filed as Exhibit 10a(8) with Annual Report on Form 10-K for the year ended December 31, 2000, File No. 001-09120, on March 6, 2001 and incorporated herein by this reference.

(12)

Filed as Exhibit 10a(24) with Quarterly Report on Form 10-Q for the quarter ended June 30, 2001, File No. 001-09120, on August 9, 2001 and incorporated herein by this reference.

(13)

Filed as Exhibit 10a(12) with Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-09120, on March 1, 2002 and incorporated herein by this reference.

(14)

Filed as Exhibit 10a(14) with Annual Report on Form 10-K for the year ended December 31, 2005, File No. 001-09120, and incorporated herein by reference.

(15)

Filed as Exhibit 10 with Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, File No. 001-09120, on October 30, 2003 and incorporated herein by this reference.

(16)

Filed as Exhibit 10a(17) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.

(17)

Filed as Exhibit 10a(20) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-09120, on February 26, 2003 and incorporated herein by this reference.

(18)

Filed as Exhibit 10a(21) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-09120, on February 25, 2004 and incorporated herein by this reference.

(19)

Filed as Exhibit 99.2 with Current Report on Form 8-K, File No. 001-09120, on December 20, 2004 and incorporated herein by this reference.

(20)

Filed as Exhibit 3.1 to Registration Statement on Form S-4, No. 333-69228 filed on October 5, 2001 and incorporated herein by this reference.

(21)

Filed as Exhibit 3.2 to Registration Statement on Form S-4, No. 333-69228 filed on October 5, 2001 and incorporated herein by this reference.

(22)

Filed as Exhibit 3.6 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(23)

Filed as Exhibit 3.7 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(24)

Filed as Exhibit 3.8 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(25)

Filed as Exhibit 3.9 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(26)

Filed as Exhibit 3.10 to Registration Statement on Form S-3, No. 333-105704 filed on May 30, 2003 and incorporated herein by this reference.

(27)

Filed as Exhibit 4.1 to Registration Statement on Form S-4, No. 333-69228 filed on October 5, 2001 and incorporated herein by this reference.

(28)

Filed as Exhibit 4.7 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2002, File No. 000-49614, on May 15, 2002 and incorporated herein by this reference.

(29)

Filed as Exhibit 10a(13) with Annual Report on Form 10-K for the year ended December 31, 2005, File No. 000-49614, and incorporated herein by reference.

(30)

Filed as Exhibit 3(a) with Quarterly Report on Form 10-Q for the quarter ended June 30, 1986, File No. 001-00973, on August 28, 1986 and incorporated herein by this reference.

(31)

Filed as Exhibit 3a(2) with Annual Report on Form 10-K for the year ended December 31, 1987, File No. 001-00973, on March 28, 1988 and incorporated herein by this reference.

(32)

Filed as Exhibit 3a(3) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.

(33)

Filed as Exhibit 3a(4) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.

(34)

Filed as Exhibit 3a(5) on Form 8-A, File No. 001-00973, on February 4, 1994 and incorporated herein by this reference.

(35)

Filed as Exhibit 3.3 with Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, File No. 001-00973 on May 4, 2007 and incorporated herein by this reference.

(36)

Filed as Exhibit 4b(1) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(37)

Filed as Exhibit 4b(2) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(38)

Filed as Exhibit 4b(3) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(39)

Filed as Exhibit 4b(4) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(40)

Filed as Exhibit 4b(5) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(41)

Filed as Exhibit 4b(6) with Annual Report on Form 10-K for the year ended December 31, 1980, File No. 001-00973 on February 18, 1981 and incorporated herein by this reference.

(42)

Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973 on July 1, 1991 and incorporated herein by this reference.

(43)

Filed as Exhibit 4(ii) on Form 8-A, File No. 001-00973 on May 25, 1993 and incorporated herein by this reference.

(44)

Filed as Exhibit 4(i) with Current Report on Form 8-K, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.

(45)

Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.

(46)

Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on February 3, 1994 and incorporated herein by this reference.

(47)

Filed as Exhibit 4(i) on Form 8-A, File No. 001-00973 on March 15, 1994 and incorporated herein by this reference.

(48)

Filed as Exhibit 4a(91) with Quarterly Report on Form 10-Q for the quarter ended September 30, 1994, File No. 001-00973, on November 8, 1994 and incorporated herein by this reference.

(49)

Filed as Exhibit 4a(2) on Form 8-A, File No. 001-00973 on January 26, 1996 and incorporated herein by this reference.

(50)

Filed as Exhibit 4a(3) on Form 8-A, File No. 001-00973 on January 26, 1996 and incorporated herein by this reference.

(51)

Filed as Exhibit 4 on Form 8-A, File No. 001-00973 on May 15, 1998 and incorporated herein by this reference.

(52)

Filed as Exhibit 4a(97) with Annual Report on Form 10-K for the year ended December 31, 2002, File No. 001-00973 on February 25, 2003 and incorporated herein by this reference.

(53)

Filed as Exhibit 4a(98) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(54)

Filed as Exhibit 4a(99) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(55)

Filed as Exhibit 4a(25) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

(56)

Filed as Exhibit 4a(26) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

(57)

Filed as Exhibit 4a(27) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

(58)

Filed as Exhibit 4a(28) with Annual Report on Form 10-K for the year ended December 31, 2004, File No. 001-00973 on March 1, 2005 and incorporated herein by this reference.

(59)

Filed as Exhibit 4a(100) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(60)

Filed as Exhibit 4a(101) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(61)

Filed as Exhibit 4a(102) with Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-00973 on February 25, 2004 and incorporated herein by this reference.

(62)

Filed as Exhibit 4 with Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, File No. 001-00973 on August 3, 2004 and incorporated herein by this reference.

(63)

Filed as Exhibit 4 with Current Report on Form 8-K, File No. 001-00973 on December 1, 1993 and incorporated herein by this reference.

(64)

Filed as Exhibit 4.6 to Registration Statement on Form S-3, No. 333-76020 filed on December 27, 2001 and incorporated herein by this reference.

(65)

Filed as Exhibit 10a(12) with Annual Report on Form 10-K for the year ended December 31, 2005, File No. 001-00973, and incorporated herein by reference.

SCHEDULE II

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
Schedule II Valuation and Qualifying Accounts
Years Ended December 31, 2007 December 31, 2005

Column A

Column B

Column C

Column D

Column E

Description

Balance at Beginning of Period

Additions

Deductions describe

Balance at End of Period

Charged to cost and expenses

Charged to other accounts describe

(Millions)

2007:

Allowance for Doubtful Accounts

$

47

$

64

$

$

65

(A)

$

46

Materials and Supplies Valuation Reserve

8

2

4

(B)

6

Other Valuation Allowances

8

8

2006:

Allowance for Doubtful Accounts

$

42

$

77

$

$

72

(A)

$

47

Materials and Supplies Valuation Reserve

6

7

5

(B)

8

Other Reserves

3

3

(C)

Other Valuation Allowances

8

8

2005:

Allowance for Doubtful Accounts

$

34

$

65

$

$

57

(A)

$

42

Materials and Supplies Valuation Reserve

9

3

(B)

6

Other Reserves

2

1

(C)

3

Other Valuation Allowances

8

8

(A)

Accounts Receivable/Investments written off.

(B)

Reduced reserve to appropriate level and to remove obsolete inventory.

(C)

Includes various liquidity, credit and bad debt reserves.

PSEG POWER LLC
Schedule II Valuation and Qualifying Accounts
Years Ended December 31, 2007 December 31, 2005

Column A

Column B

Column C

Column D

Column E

Description

Balance at Beginning of Period

Additions

Deductions describe

Balance at End of Period

Charged to cost and expenses

Charged to other accounts describe

(Millions)

2007:

Materials and Supplies Valuation Reserve

$

8

$

2

$

$

4

(A)

$

6

2006:

Materials and Supplies Valuation Reserve

$

6

$

7

$

$

5

(A)

$

8

Other Reserves

3

3

(B)

2005:

Materials and Supplies Valuation Reserve

$

9

$

$

$

3

(A)

$

6

Other Reserves

2

1

(B)

3

(A)

Reduced reserve to appropriate level and removed obsolete inventory.

(B)

Includes various liquidity, credit and bad debt reserves.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
Schedule II Valuation and Qualifying Accounts
Years Ended December 31, 2007 December 31, 2005

Column A

Column B

Column C

Column D

Column E

Description

Balance at Beginning of Period

Additions

Deductions describe

Balance at End of Period

Charged to cost and

expenses

Charged to other accounts describe

(Millions)

2007:

Allowance for Doubtful Accounts

$

46

$

64

$

$

65(A

)

$

45

2006:

Allowance for Doubtful Accounts

$

41

$

77

$

$

72(A

)

$

46

<u>2005:</u>

Allowance for Doubtful Accounts

$

34

$

64

$

$

57(A

)

$

41

(A)

Accounts Receivable/Investments written off.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

By:

/S/ RALPH IZZO

Ralph Izzo
Chairman of the Board, President and
Chief Executive Officer

Date: February 27, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature

Title

Date

/S/ RALPH IZZO

Ralph Izzo

Chairman of the Board, President,
Chief Executive Officer and
Director (Principal Executive Officer)

February 27, 2008

/S/ THOMAS M. O FLYNN

Thomas M. O Flynn

Executive Vice President and Chief Financial Officer (Principal Financial Officer)

February 27, 2008

/S/ DEREK M. DIRISIO

Derek M. DiRisio

Vice President and Controller (Principal Accounting Officer)

February 27, 2008

/S/ CAROLINE DORSA

Caroline Dorsa

Director

February 27, 2008

/S/ ERNEST H. DREW

Ernest H. Drew

Director

February 27, 2008

/S/ ALBERT R. GAMPER, JR.

Albert R. Gamper, Jr.

Director

February 27, 2008

/S/ CONRAD K. HARPER

Conrad K. Harper

Director

February 27, 2008

/S/ WILLIAM V. HICKEY

William V. Hickey

Director

February 27, 2008

/S/ SHIRLEY ANN JACKSON

Shirley Ann Jackson

Director

February 27, 2008

/S/ THOMAS A. RENYI

Thomas A. Renyi

Director

February 27, 2008

/S/ RICHARD J. SWIFT

Richard J. Swift

Director

February 27, 2008

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC

By:

/S/ WILLIAM LEVIS

William Levis
President and
Chief Operating Officer

Date: February 27, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature

Title

Date

/S/ RALPH IZZO

Ralph Izzo

Chairman of the Board and Chief
Executive Officer and Director

(Principal Executive Officer)

February 27, 2008

/S/ THOMAS M. O FLYNN

Thomas M. O Flynn

Executive Vice President and Chief
Financial Officer and Director
(Principal Financial Officer)

February 27, 2008

/S/ DEREK M. DIRISIO

Derek M. DiRisio

Vice President and Controller
(Principal Accounting Officer)

February 27, 2008

/S/ STEPHEN C. BYRD

Stephen C. Byrd

Director

February 27, 2008

/S/ WILLIAM LEVIS

William Levis

Director

February 27, 2008

/S/ RICHARD P. LOPRIORE

Richard Lopriore

Director

February 27, 2008

/S/ KEVIN J. QUINN

Kevin J. Quinn

Director

February 27, 2008

/S/ R. EDWIN SELOVER

R. Edwin Selover

Director

February 27, 2008

/S/ ELBERT C. SIMPSON

Elbert C. Simpson

Director

February 27, 2008

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

By:

/S/ RALPH LAROSSA

Ralph LaRossa
President and
Chief Operating Officer

Date: February 27, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signatures of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Signature

Title

Date

/S/ RALPH IZZO

Ralph Izzo

Chairman of the Board and Chief
Executive Officer and Director
(Principal Executive Officer)

February 27, 2008

/S/ THOMAS M. O FLYNN

Thomas M. O Flynn

Executive Vice President and Chief
Financial Officer (Principal Financial
Officer)

February 27, 2008

/S/ DEREK M. DIRISIO

Derek M. DiRisio

Vice President and Controller
(Principal Accounting Officer)

February 27, 2008

/S/ CAROLINE DORSA

Caroline Dorsa

Director

February 27, 2008

/S/ ALBERT R. GAMPER, JR.

Albert R. Gamper, Jr.

Director

February 27, 2008

/S/ CONRAD K. HARPER

Conrad K. Harper

Director

February 27, 2008

EXHIBIT INDEX

The following documents are filed as a part of this report:

a.

PSEG:

Exhibit 10a(1): Amended and Restated Limited Supplemental Benefits Plan for Certain Employee, effective April 2007

Exhibit 10a(2): Amended Mid Career Hire Supplemental Retirement Income plan, effective April 2007

Exhibit 10a(3): Amended Retirement Income Reinstatement Plan for Non-Represented Employees, effective April 2007

Exhibit 10a(4): Employment Agreement with William Levis dated December 8, 2006

Exhibit 10a(5): 2007 Equity Compensation Plan for Outside Directors

Exhibit 12: Computation of Ratios of Earnings to Fixed Charges

Exhibit 14: Code of Ethics

Exhibit 21: Subsidiaries of the Registrant

Exhibit 23: Consent of Independent Registered Public Accounting Firm

Exhibit 31a: Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

Exhibit 31b: Certification by Thomas M. O Flynn Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

Exhibit 32a: Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

Exhibit 32b: Certification by Thomas M. O Flynn Pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

b.

Power:

Exhibit 10a(1): Amended and Restated Limited Supplemental Benefits Plan for Certain Employee, effective April 2007

Exhibit 10a(2): Amended Mid Career Hire Supplemental Retirement Income plan, effective April 2007

Exhibit 10a(3): Amended Retirement Income Reinstatement Plan for Non-Represented Employees, effective April 2007

Exhibit 10a(4): Employment Agreement with William Levis dated December 8, 2006

Exhibit 12a: Computation of Ratios of Earnings to Fixed Charges

Exhibit 14: Code of Ethics

Exhibit 23b: Consent of Independent Registered Public Accounting Firm

Exhibit 31e: Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

Exhibit 31f: Certification by Thomas M. O Flynn Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

Exhibit 32e: Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

Exhibit 32f: Certification by Thomas M. O Flynn Pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

c.

PSE&G:

Exhibit 4a(28): Supplemental Indenture to Mortgage Indenture, dated April 1, 2007

Exhibit 10a(1): Amended and Restated Limited Supplemental Benefits Plan for Certain Employee, effective April 2007

Exhibit 10a(2): Amended Mid Career Hire Supplemental Retirement Income plan, effective April 2007

Exhibit 10a(3): Amended Retirement Income Reinstatement Plan for Non-Represented Employees, effective April 2007

Exhibit 10a(5): 2007 Equity Compensation Plan for Outside Directors

Exhibit 12b: Computation of Ratios of Earnings to Fixed Charges

Exhibit 12c: Computation of Ratios of Earnings to Fixed Charges Plus Preferred Stock Dividend Requirements

Exhibit 14: Code of Ethics

Exhibit 21a: Subsidiaries of Registrant

Exhibit 23a: Consent of Independent Registered Public Accounting Firm

Exhibit 31c: Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

Exhibit 31d: Certification by Thomas M. O Flynn Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act

Exhibit 32c: Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code

Exhibit 32d: Certification by Thomas M. O Flynn Pursuant to Section 1350 of Chapter 63 of Title 18 of the US Code